

3.2 AIR QUALITY

This section discusses the impact on air resources from the BP Cherry Point Cogeneration Project. It addresses potential impacts associated with the proposed project and identifies mitigation measures designed to limit those impacts. The analysis in this section is based on information from the Application for Site Certification prepared for this project (BP 2002, Appendix E).

In addition to evaluating the emissions resulting from the cogeneration facility alone, this section describes the Applicant's estimates of emission reductions that would occur with the cogeneration aspect of the proposal. As indicated in Section 1.2.1, BP Cherry Point Refinery Need, one of the purposes of the cogeneration project is to supply both steam and electricity to the existing refinery. The refinery's purchase of cogeneration facility steam would allow the removal of existing less efficient refinery utility boilers, leading to a reduction in regional emissions of particulate matter less than 10 microns in size (PM₁₀) and nitrogen oxides (NO_x). The short and long-range air quality impacts of both the cogeneration facility emissions and the refinery reductions are discussed in more detail below.

3.2.1 Regulatory Framework

Under Chapter 80.50 Revised Code of Washington (RCW), the authority for permit review and issuance of air permits is granted to the EFSEC for thermal generating power plants capable of generating 350 MW or more of electricity. The U.S. Environmental Protection Agency (EPA) has delegated to EFSEC the issuance of federal Prevention of Significant Deterioration (PSD) permits for facilities regulated under Chapter 80.50 RCW. EFSEC reviews applications for air emissions resulting from the operation of such facilities pursuant to the requirements of Chapter 463-39 WAC. EFSEC has adopted the substantive requirements of the Washington Department of Ecology regulations for air pollution sources as codified in Chapters 173-400 WAC (General Regulations for Air Pollution Sources), Chapter 173-401 WAC (Air Operating Permit Program), Chapter 173-406 WAC (Acid Rain Regulation), and Chapter 173-460 (Controls for New Sources of Toxic Air Pollutants).

Air Quality Standards

United States

The proposed cogeneration facility would be regulated according to applicable U.S. federal and Washington State laws and regulations. Pursuant to the Clean Air Act of 1970, the EPA established air quality standards for the following air pollutants: ozone (O₃), carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO₂), particulate matter (PM₁₀, PM_{2.5}), and sulfur dioxide (SO₂). These include primary standards that have been established to protect human health and secondary standards to protect the public welfare. Ecology has also adopted Washington Ambient Air Quality Standards (WAAQS) similar to the National Ambient Air Quality Standards (NAAQS), and has included standards for total suspended particulate (TSP).

Particulate matter includes both naturally occurring and man-made particles with a diameter of less than 10 microns or 2.5 microns, respectively. Local and regional contributions of particulate matter include sea salt, pollen, smoke from forest fires and wood stoves, road dust, industrial emissions, and agricultural dust. Particles of this size are small enough to be drawn deep into the respiratory system where they can contribute to infection and reduced resistance to disease (Canadian Federal Government 2002).

Table 3.2-1 summarizes the federal and state primary and secondary standards for the criteria pollutants, and the averaging time for determining compliance with the standards. It also presents the increments under the EPA's PSD program and the EPA PSD Class II significance levels for air quality that are applicable to the proposed project.

Canada

For purposes of review of the impacts to air quality on a regional basis, Canadian regulatory standards and objectives were considered. The Canadian Environmental Protection Act provides for three levels of air quality objectives: desirable, acceptable, and tolerable, which correspond to degrees of environmental damage or potential health effects. The Province of British Columbia also has established air quality objectives that are similar to the Canadian national objectives, and, where no comparable federal objectives exist, the Greater Vancouver Regional District (GVRD) has proposed objectives for pollutants of concern within its jurisdiction. Level A is a descriptor used by GVRD that is equivalent to the desirable objective, and Level B is a descriptor that is equivalent to the acceptable objective in the Canadian Environmental Protection Act. The Canadian Ministers of Environment have established nationwide standards for PM_{2.5} and O₃. These standards establish goals for the year 2010 rather than regulatory limits. Table 3.2-2 summarizes the Canadian National Ambient Air Quality Objectives and Standards.

Regulatory Requirements

The EPA and Ecology have developed air quality regulations and guidelines that require all new or modified "major sources" of air emissions to undergo a rigorous permitting process before commencing construction. The federal program is called New Source Review (NSR). The PSD program is within the overall federal NSR program. The provisions of the federal PSD program are contained in 40 CFR 52.21.

New Source Review

The NSR program applies to new or modified sources that could cause a significant increase in emissions of air pollutants. The objectives of the NSR process are to demonstrate that air emissions from the new source will not significantly impact ambient air quality near the facility and that state-of-the-art emission controls will be applied. NSR incorporates both state and federal requirements.

To satisfy the general NSR requirements, the following information must be submitted:

- Notice of Construction Application form and associated information. This application form is included at the front of the PSD application.
- PSD Applicability Analysis
- "Top-down" BACT Analysis
- Toxic Air Pollutant Review (WAC 173-460)
- Air Quality Modeling Analysis

The requirements for these separate review elements are described in further detail below.

Prevention of Significant Deterioration

PSD review regulations apply to new or modified sources located in an attainment area that have the potential to emit criteria pollutants in excess of predetermined "*de minimus*" values (40 CFR Part 51). For new generation facilities, these values are 100 tons per year (tpy) of criteria pollutants for 28 specific source categories, including power generating facilities, and 250 tpy for all others. The proposed project would be a PSD source because it would emit more than 100 tpy of NO_x, CO, PM₁₀, and PM_{2.5}. Also, the projected potential to emit annual emissions of volatile organic compounds (VOC), SO₂, and sulfuric acid mist (H₂SO₄) exceeds the individual significant emission rate thresholds listed in WAC 173-400-030. VOC is defined as any organic compound that participates in atmospheric photochemical reactions. Therefore, the proposed project is also subject to PSD review for those pollutants.

The PSD review process evaluates existing ambient air quality, the potential impacts of the proposed source on ambient air quality, whether the source would contribute to a violation of the NAAQS, and a review of the Best Available Control Technology (BACT). It should be noted that although NAAQS have been established for PM 2.5, the designation of attainment, non-attainment, and unclassified areas has not yet been performed for this pollutant. PM 2.5 is therefore not a regulated pollutant under the PSD program at this time.

PSD restricts the degree of ambient air quality deterioration that would be allowed by assigning increments for criteria pollutants based on the classification (attainment, non-attainment, or unclassified) of the area. PSD increments have been established for certain criteria pollutants and are interpreted as the maximum allowable ground-level increase of a pollutant concentration. Class I areas are assigned to federally protected wilderness areas, such as national parks, and allow the lowest increment of permissible deterioration. This essentially precludes development near these areas. Class II areas are designed to allow for moderate, controlled growth, and Class III areas allow for heavy industrial use, but in all cases the pollution concentrations cannot violate any of the NAAQSs.

The Class I areas closest to the proposed project include North Cascades National Park, Olympic National Park, Glacier Peak Wilderness Area, Alpine Lakes Wilderness Area, and Pasayten Wilderness Area (Figure 3.2-1). The area around the proposed project is designated Class II where less stringent PSD increments apply. Class I and II increments are shown with the ambient air quality standards in Table 3.2-1.

Significant Impact Levels (SILs) are used in the air quality impact analysis. The SILs are a screening tool to determine the extent of the air quality analysis required to demonstrate compliance with the NAAQSs and PSD increments. The SILs are typically 1 to 5% of the ambient air quality standards and are well below any levels that could lead to adverse health or welfare impacts. These SILs are more restrictive than the NAAQSs and the Canadian National Ambient Air Quality Objectives and Standards.

According to analysis methodologies established by Ecology and the EPA, the impact from a source is not required to be below the SILs. However, these levels set a worst-case scenario, so if the impacts of a source are below the SILs, state and federal agencies consider the impacts to be inconsequential and no further evaluation is required.

Finally, the PSD program also requires an analysis of the impairment to soils and vegetation, and an analysis of visibility, regional haze, and deposition impacts on Class I areas.

State/Local Emission Limits and Best Available Control Technology

As part of the PSD process, EFSEC is reviewing the Applicant's evaluation of alternative emission control technologies. The determination of which control technology best protects ambient air quality is made by the regulatory agency on a case-by-case basis taking into account the associated economic, energy, and environmental impacts. The analysis for BACT identifies pollutant-specific alternatives for emission control, and the costs and benefits of each alternative technology. BACT would reduce emissions of toxic air pollutants, along with those of criteria pollutants. For example, low-sulfur fuel, such as natural gas, is a BACT because of its lower emissions of criteria and toxic air pollutants over other fuels, such as fuel oil or coal. Combustion controls also reduce criteria pollutants by optimizing combustion and reducing pollutants emitted in the exhaust stream.

The determination of BACT at the time of the final air emissions permit review would define the emission limits for the proposed project. BACT for NO_x typically consists of dry, low NO_x technology, or SCR, which is a post-combustion control that uses ammonia and a catalyst to reduce NO_x emissions. Any unreacted ammonia is emitted as a toxic air pollutant, however, and is regulated by Washington State.

Other Air Permit Requirements

New Source Performance Standards

The EPA has adopted federal emission standards applicable to various combustion sources. These emission standards are referred to as the New Source Performance Standards (NSPS). EPA set forth the NSPS for stationary combustion turbines in 40 CFR 60, Subpart GG, dated September 1979. These require that NO_x emissions do not exceed 103 parts per million dry volume (ppmdv) at full load operation and that SO₂ emissions not exceed 150 ppmv. They also prohibit the use of fuel containing more than 0.8% sulfur by weight.

Figure 3.2-1

The duct burners are subject to the NSPS for steam generating units in 40 CFR 60, Subpart Db, which limit the NO_x emission for the duct burners to 0.20 lb/mmBt. No other NSPS emissions standards are applicable to this proposed power generating facility.

Acid Rain

Title IV of the Clean Air Act (also known as the “acid rain” rules) applies to utility projects that started commercial operation on or after November 15, 1990, produce electricity for sale and do not fall into one of the regulatory exemptions. These rules are contained in 40 CFR Parts 72, 75, and 76 and have been adopted into WAC 173-406. The “acid rain” rules will apply to the proposed project’s combustion turbines and duct burners because these units will be utility units serving one or more generators with a nameplate capacity of greater than 25 MW.

The Title IV program consists of three primary requirements. To meet these requirements the Applicant would have to:

1. Submit an “acid rain” permit application at least 24 months before the anticipated date for start of operations,
2. Be subject to requirements for continuous emissions monitoring for NO_x and dilutents gas (O₂ or CO₂) and,
3. Be subject to the “acid rain” recordkeeping and reporting requirements, including the requirement to obtain and document SO₂ allowances.

Hazardous Air Pollutant Regulations

According to EPA Interpretive Rule (Federal Register 65 FR 21363), the proposed cogeneration facility is not categorically exempt from “case-by-case” Maximum Available Control Technology (MACT) determinations (Clean Air Act [CAA] Section 112). However, because no individual hazardous air pollutants (HAP) will have an emission rate greater than 10 tpy and no combination of HAPs will have a total cumulative annual emission rate of greater than 25 tpy, the facility is not subject to the MACT requirements.

No current National Emission Standards for Hazardous Air Pollutants (NESHAPS), as regulated under 40 CFR 61, are applicable to the cogeneration facility, and no current or proposed NESHAPS for sources regulated under 40 CFR 63 apply to the facility. In the future, stationary combustion turbines will be subject to NESHAPS, but since it has not yet been adopted, an applicability determination can not be made at this time.

Title V – Air Operating Permit

The cogeneration facility would be subject to the federal Clean Air Act Part 70 – Title V air operating permit program. The Applicant would have to file a permit application 12 months after facility operations commence.

Table 3-2.1: Ambient Air Quality Standards and Significant Impact Levels

Criteria Pollutants	Averaging Period	National				State of Washington ¹		PSD		EPA Significant Impact Level	
		Primary Standards ¹		Secondary Standards ¹		Class I µg/m ³		Class II µg/m ³	Class I µg/m ³	Class II µg/m ³	
		ppm	µg/m ³	ppm	µg/m ³	ppm	µg/m ³				
Total Suspended Particulate	annual	--	--	--	--	--	60	--	--	--	--
	24-hour	--	--	--	--	--	150	--	--	--	--
Sulfur Dioxide	annual	0.03	80	--	--	0.02	52 ²	2	20	0.1	1
	24-hour	0.14	365	--	--	0.10	262 ²	5	91	0.2	5
	three-hour	0.14	--	0.5	1300	--	--	25	512	1.0	25
	one-hour	--	--	--	--	0.40 ³	1050 ²	--	--	--	--
PM ₁₀	annual	--	50	--	50	--	50	4	17	0.2	1
	24-hour	--	150	--	150	--	150	8	30	0.3	5
PM _{2.5}	annual	--	15	--	15	--	--	--	--	--	--
	24-hour	--	65	--	65	--	--	--	--	--	--
Carbon Monoxide	eight-hour	9	10,000	--	--	9	10,000 ²	--	--	--	500
	one-hour	35	40,000	--	--	35	40,000 ²	--	--	--	2,000
Ozone	one-hour	0.12	235	0.12	235	0.12	235 ²	--	--	--	--
	eight-hour	0.08	176	0.08	176	--	--	--	--	--	--
Nitrogen Dioxide	annual	0.053	100	0.053	100	0.05	100	2.5	25	0.1	1
Lead	quarterly	--	1.5	--	1.5	--	--	--	--	--	--

Source: WAC 173-400 and 40 CFR 52.21

Notes: µg/m³ = micrograms per cubic meter

ppm = parts per million by volume, dry basis

1 Annual standards never to be exceeded; short-term standards not to be exceeded more than once per year unless otherwise noted.

2 Values are calculated equivalent to regulated value.

3 The 0.40 ppm standard is not to be exceeded more than once per year

Table 3.2-2: Canadian National Ambient Air Quality Objectives and Standards ¹

Pollutant	Averaging Period	Canada Objectives ² (µg/m ³)		BC and GVRD Objectives ³ (µg/m ³)		Canada-Wide Standard (µg/m ³)
		Desirable	Acceptable	Level A	Level B	
Sulfur dioxide	annual	30	60	25	50	---
	24-hour	150	300	160	260	---
	three-hour	---	---	375	665	---
	one-hour	450	900	450	900	---
Total suspended particulate	annual	60	70	60	70	---
	24-hour	---	120	150	200	---
Inhalable particulate (PM ₁₀) ⁴	annual	---	---	---	30	---
	24-hour	---	---	---	50	---
Fine particulate (PM _{2.5}) ^{5,6}	24-hour	---	---	---	---	30
Carbon monoxide	eight-hour	6,000	15,000	5,500	11,000	---
	one-hour	15,000	35,000	14,300	28,000	---
Ozone	24-hour	30	50	---	---	---
	eight-hour ⁵	---	---	---	---	127
	one-hour	100	160	---	---	---
Nitrogen dioxide	annual	60	100	---	---	---
	24-hour	---	200	---	---	---
	one-hour	---	400	---	---	---
Total reduced sulfur	24-hour	---	---	3	6	---
	one-hour	---	---	7	28	---
Lead	annual	---	---	2	2	---
	24-hour	---	---	4	4	---
Zinc	annual	---	---	3	3	---
	24-hour	---	---	5	5	---

Source: GVRD 2002

1 The tolerable objective is the least strict of the Canadian objectives, so no column is presented in the table showing these values.

2 Federal objective unless otherwise noted.

3 British Columbia Provincial objective unless otherwise noted.

4 GVRD objective.

5 Canada-wide standard to be achieved by year 2010.

6 Based on the 98th percentile, average over a three-year period, and established by the Canadian regulatory agencies.

Title III – Prevention of Accidental Releases

Because the cogeneration facility proposes the use of anhydrous ammonia in the SCR emissions control system, the facility could become subject to the Prevention of Accidental Release provisions of the 1990 Clean Air Act Amendment, Section 112. If the proposed cogeneration facility is subject to these provisions, a Risk Management Plan would be required covering storage, handling, and use of ammonia.

3.2.2 Existing Conditions

Climate

The proposed project is in the Puget Sound lowlands, a north-south topographical depression bordered on the east by the Cascade Mountains and the west by the Olympic Mountains and

Vancouver Island. The project site is located in an area known as the Mountain View upland. The climate at the site is influenced by marine air that flows east from the Pacific Ocean and through the Straits of Georgia and Juan de Fuca. Occasionally, cold, dry continental air flows from the east-northeast through the Fraser River canyon.

According to data from the BP Cherry Point Refinery's meteorological seven-year monitoring program (1995-2001), the maximum high temperature recorded was 86°F (1998) and the record low temperature was 10°F (1996). Over the seven years of monitoring, January and December had the lowest temperature average of 40°F while July and August had the highest average of 60°F. Relative humidity is not measured as part of the BP meteorological measurements program. However, other published data demonstrate the influence of the marine climate at the project site. Afternoon humidity readings are typically in the 60% range during summer months and in the mid- to upper 80% range during winter months (Pacific Northwest River Basin Commission 1968). Higher relative humidity can be expected with the passage of migratory storm systems from the west. Lower humidity can be expected with high pressure over eastern British Columbia and eastern Washington.

Predominant winds at the project site are from the south to south-southwest and from the east-northeast. On an annual basis, winds from the south and south-southwest occur with a frequency of about 24%. Winds from the east or east-northeast occur about 21% of the time, and winds from the west to northwest occur about 20% of the time.

Dust

The air in the vicinity of the project site is generally free of dust. The area around the site is predominantly rural, agricultural land with some populated areas within a few miles of the site. The agricultural land is predominantly covered with grass and is used for cattle grazing. Typical farming activities, such as soil tilling that create dust clouds, occur infrequently.

Dust-control measures regulated by the Northwest Air Pollution Authority (NWAPA) are aimed at preventing particulate matter from becoming airborne from untreated open areas (NWAPA 2003).

Odor

Over the past three years the NWAPA has received several odor-related complaints due to the existing refinery. A sulfur smell has been the most prevalent complaint, however, local officials who responded to the complaints have not detected or found any of these odors. Compared to other facilities of this type, the existing refinery has received minimal complaints (Billington, pers. comm., 2003).

Existing Air Quality

United States

Based on air quality monitoring information, Ecology and the EPA designate geographic regions as being in “attainment” or “nonattainment” if the region is in compliance or noncompliance with air pollutants listed under the NAAQSs (Table 3.2-1). Whatcom County and the surrounding area are in attainment for all air pollutants regulated by the NAAQS and the WAAQS.

The NWAPA operates monitoring sites for a variety of air pollutants within Whatcom County. Pollutants monitored by or reported to the NWAPA include SO₂, PM₁₀, PM_{2.5} and O₃. Data are reported as an air quality index (AQI) where levels are characterized as good, moderate, or unhealthy.

Data from the Lynden-Custer site indicate that no moderate or unhealthy days occurred in calendar year 2001 (all 365 days were in the “good” range). At the more urban Bellingham site, there were no moderate or unhealthy days for PM₁₀ (all 365 days were in the “good” range) and there were 6 days where the PM_{2.5} air quality index was in the moderate range. The Lynden-Custer site is representative of a rural “background” area while the Bellingham site is representative of a more mixed urban and rural area, where higher pollution levels are typically expected.

In Bellingham (Yew Street), PM₁₀ is collected continuously by a Rupprecht and Patashnick TEOM 1400 sampler. These data are summarized and reported by the NWAPA. For the years summarized, the maximum 24-hour PM₁₀ concentration was 53 micrograms per cubic meter (µg/m³). According to the three-year data presented, the maximum annual average PM₁₀ concentration in Bellingham was 13.7 µg/m³. In March 1999, this PM₁₀ sampler was moved to its current Yew Street location from its previous location on Iowa Street.

NWAPA has operated a PM_{2.5} sampler in Bellingham since February 1999 (Yew Street). This site is currently co-located with the Bellingham PM₁₀ measurements. The NWAPA also reports ozone data for a Lynden-Custer site. For calendar year 2001, no moderate or unhealthy days were experienced (all 365 days were in the “good” range). BP also operates an SO₂ monitor at the refinery. According to the NWAPA data summary for SO₂ at Blaine, all 365 days in calendar year 2001 were in the “good” range.

Air quality monitoring indicates that since 1999 (for PM₁₀, PM_{2.5}) and 2001 (for SO₂ and O₃), no moderate or unhealthy days have been recorded in Whatcom County.

Canada

Ambient air quality data have also been summarized by pollutant for the closest ambient monitoring stations in Canada. The Surrey and Langley sites are the closest sites in Canada to the project that monitor PM₁₀, CO, NO_x, and O₃. They are located approximately 16.2-mile to the north and northeast, respectively, from the cogeneration project site. The Richmond and

Abbotsford sites are the closest sites in Canada that monitor SO₂, and they are located 23 miles to the northwest and 22 miles to the northeast, respectively, from the cogeneration project site. Pitt Meadows and Vancouver Airport are the closest sites in Canada to the cogeneration project site that measure PM_{2.5}, and they are located 24 miles to the north and 27 miles to the northwest, respectively, from the project site. A summary of the ambient monitoring sites is shown in Table 3.2-3.

Table 3.2-3: Ambient Monitoring Stations in Canada

Station	Station ID	Distance from Project Site (miles)	Direction from Project Site	Pollutants Measured
Surrey	T15	16.5	N	PM ₁₀ , CO, NO ₂ , O ₃
Richmond	T17	23.1	NW	SO ₂
Pitt Meadows	T20	24.5	N	PM _{2.5}
Langley	T27	16.3	NE	PM ₁₀ , CO, NO ₂ , O ₃
Vancouver Airport	T31	27.0	NW	PM _{2.5}
Abbotsford	T33	22.3	NE	SO ₂

For the Canadian air quality data, the maximum and 98th percentile concentrations for each pollutant and averaging time are summarized in Table 3.2-4. Concentrations are listed for 1999 through 2001 for the closest two ambient monitoring stations for each pollutant. The maximum values of the three years and the two stations are also listed.

Table 3.2-4: Background Concentrations in Canada ¹

Pollutant		Ambient Monitoring Station 1			Ambient Monitoring Station 2			Maximum
		1999	2000	2001	1999	2000	2001	
Maximum Concentration (µg/m ³)								
SO ₂	Annual	3	3	3	3	1	3	3
	24-hour	11	13	8	5	5	8	13
	3-hour	19	27	16	19	21	13	27
	1-hour	29	35	29	27	27	29	35
PM ₁₀	Annual	12	13	12	12	13	12	13
	24-hour	34	31	35	32	34	33	35
PM _{2.5}	Annual	8	9	5	9	9	5	9
	24-hour	24	22	19	23	29	17	29
CO	8-hour	2,436	1,740	1,624	2,668	1,740	1,508	2,668
	1-hour	2,900	2,900	2,900	2,900	2,784	4,060	2,900
NO _x	Annual	23	27	21	17	17	17	27
	24-hour	69	67	55	52	48	42	69
	1-hour	107	99	90	84	88	73	107
Ozone	24-hour	88	84	76	94	86	82	94
	1-hour	140	138	166	142	134	160	168

¹ Ambient Monitoring Station 1 is Surrey for PM₁₀, CO, O₃, and NO₂, Richmond for SO₂, and Pitt Meadows for PM_{2.5}. Ambient Monitoring Station 2 is Langley for PM₁₀, CO, O₃, and NO₂, Abbotsford for SO₂, and Vancouver Airport for PM_{2.5}

Table 3.2-4: Continued

Pollutant		Ambient Monitoring Station 1			Ambient Monitoring Station 2			Maximum
		1999	2000	2001	1999	2000	2001	
98th Percentile Concentrations for short-term averaging times (µg/m³)								
SO ₂	24-hour	5	8	5	5	5	5	8
	3-hour	8	11	8	5	8	5	11
	1-hour	21	24	16	19	19	11	24
PM ₁₀	24-hour	24	25	25	26	27	24	27
PM _{2.5}	24-hour	17	19	15	17	21	15	21
CO	8-hour	1,276	1,044	1,044	1,160	1,044	928	1,276
	1-hour	1,276	1,160	1,740	1,276	1,160	1,624	1,740
NO _x	24-hour	50	52	46	34	32	36	52
	1-hour	61	69	78	48	46	63	78
Ozone	24-hour	72	68	70	76	72	68	76
	1-hour	90	88	112	94	88	114	112

1 Ambient Monitoring Station 1 is Surrey for PM₁₀, CO, O₃, and NO₂, Richmond for SO₂, and Pitt Meadows for PM_{2.5}. Ambient Monitoring Station 2 is Langley for PM₁₀, CO, O₃, and NO₂, Abbotsford for SO₂, and Vancouver Airport for PM_{2.5}.

Monitoring Stations

The GVRD operates air quality monitoring stations in the Lower Fraser Valley of British Columbia. Similar to the United States, Canada's AQI is a measure derived by the GVRD and Lower Fraser Valley Ambient Air Quality Reports. Based on the index criteria, an AQI of less than 25 indicates good air quality. An AQI of 26 to 50 represents fair air quality levels. From 51 to 100, the AQI level is considered to be poor, and above 101 the air quality is considered to be very poor.

Air quality classified as good would show that air contaminants are near the background (ambient) levels, in which air quality poses little health risk within the region. Presently, 98% of the time air quality is at or below this level. Fair air quality within the region reflects that air contaminants are relatively low, however, sensitive individuals and ecosystems may have adverse effects. Currently, air quality is at this level less than 2% of the time. Poor air quality may adversely affect humans, animals, water, and vegetation. On average, air quality is at this level only for a few hours each year. Finally, very poor air quality can pose significant health and environmental risks within the region, leading to immediate government action (GVRD 2003).

Air quality in areas of British Columbia immediately north of the proposed project site is characterized in the good range with some hours characterized as fair. To characterize the existing air quality for areas closest to the U.S./Canada border, the most recent data available from a selection of monitoring stations were evaluated (Surrey, Richmond, Langley, and Abbotsford) and are summarized in Table 3.2-5. Poor and very poor air quality conditions were not recorded at any of these locations in 2000.

Table 3.2-5: GVRD Air Quality Index Data for 2000 ¹

Station	PM ₁₀ (24-hour)	SO ₂ (one-hour)	CO (one-hour)	O ₃ (one-hour)	NO ₂ (one-hour)
Total hours per year with an AQI level of good					
Surrey	8657	NM	8760	8728	8760
Richmond	8476	8760	8760	8748	8760
Langley	8557	NM	8760	8720	8760
Abbotsford	8525	8760	8760	8741	8760
Total hours per year with an AQI level of fair					
Surrey	103	NM	0	32	0
Richmond	284	0	0	12	0
Langley	203	NM	0	40	0
Abbotsford	235	0	0	19	0
Total hours with an AQI level of poor or very poor					
Surrey	0	NM	0	0	0
Richmond	0	0	0	0	0
Langley	0	NM	0	0	0
Abbotsford	0	0	0	0	0

Source: GVRD 2002

NM-The criteria pollutant was not monitored at this location.

Note: SO₂ is not measured at the Surrey and Langley monitoring stations.

¹ Data for calendar year 2000 are the latest available from GVRD.

Sources of Air Pollution in the Project Area

Existing emission sources in the project vicinity include the adjacent refinery, the Alcoa Intalco Works aluminum smelter (approximately 3 miles south-southeast of the project site), the Conoco-Phillips Refinery (approximately 5 miles south-southeast), and the Tenaska Washington Cogeneration power plant (approximately 5 miles to the south-southeast). The NWAPA and Ecology regulate all of these sources.

The Applicant issues annual reports to NWAPA and Ecology for review. These documents contain yearly emission data from the existing facility and are available to the public.

3.2.3 Impacts of the Proposed Action

Construction

Cogeneration Facility

Dust

The use of heavy equipment on the project site during the construction phase would generate dust. Late in the construction process onsite roads and parking areas would be constructed with asphalt over a compacted subbase.

Odors

This would be a localized air emission and is not anticipated to produce an impact.

Natural gas will be supplied to the site primarily through the existing refinery connections to the proprietary Ferndale pipeline, which connects to the West Coast Energy Pipeline at the U.S./Canada border near Sumas. If a leak occurs before preventative instrumentation/measures are conducted, a short-term odor may occur.

Combustion emissions would result from diesel construction equipment, various diesel-fueled trucks, and the private vehicles of workers commuting to the construction site. All site preparation would be completed using conventional methods of construction. General construction equipment would include, but is not limited to: heavy, medium, and light equipment such as excavators, roller compactors, front end loaders, bulldozers, graders, backhoes, dump trucks, water trucks, concrete trucks, pump trucks, utility trucks, cranes, and pile drivers.

Refinery Interface, Transmission System, Custer/Intalco Transmission Line No. 2, and Other Project Components

Construction of the pipelines, transmission lines, and other project components would generate short-term emissions, including fugitive dust and construction equipment exhaust emissions. Fugitive dust would be controlled by conventional construction practices (e.g., road watering, covering of dirt piles) to comply with state regulations.

Operation and Maintenance

The following section relates to information dealing with the operation and maintenance of the proposed cogeneration facility. All other aspects of the proposed project such as the refinery interface, transmission system, Custer/Intalco Transmission Line No. 2, and other project components are not addressed because of the lack of air emissions.

Emission Sources and Emission Controls

The principal sources of emissions from the proposed project during startup and operation would occur from up to three combustion turbines fired by natural gas, and three HRSGs.

Each HRSG would be equipped with low- NO_x duct burners and with selective catalytic reduction and oxidation catalyst systems for the removal of NO_x and CO, respectively. Steam will be produced at high pressure in the HRSG and sent to a single STG. For additional information, see Chapter 2.

The three combustion turbines would be equipped with dry low NO_x combustors that minimize the formation of NO_x and CO. GE would guarantee exhaust concentrations from the combustion gas turbine of 9 parts per million (ppm) for both NO_x and CO. A SCR catalyst bed and ammonia injection grids for the control of NO_x emissions will be installed in the HRSG, as well as a catalytic oxidation bed for the control of CO emissions. Because natural gas is a clean-burning

fuel, there would be inherently low amounts of sulfur formed as a result of the combustion process. Annual emissions rates for NO_x (2.5 ppm) and CO (2.0 ppm) were proposed. Anhydrous ammonia would be used in the SCR control system and some unreacted ammonia would exit the facility stack as ammonia “slip.” However, this ammonia slip would be limited to 5 ppm.

A cooling water system would condense the steam coming from the steam turbine. Cooling water would itself be cooled within the multi-cell cooling tower. The cooling towers would be designed with a very efficient drift elimination system to minimize the formation of PM₁₀. In a mechanical-drift cooling tower there is always a certain amount of water in the form of mist (drift) containing dissolved solids that would exit through the cooling tower stacks. As the drift evaporates, the dissolved solids would form particulate, thereby adding to the PM₁₀ emissions. Typically, cooling towers are designed to maintain a drift at 0.008 % of the amount of circulating water flow. The proposed project would incorporate ultra-low drift elimination devices in the cooling towers, which would maintain drift at a level of 0.001% of the amount of circulating water flow. Only a portion of the drift is particulate matter; the remainder is water, which evaporates.

The features listed below, which are incorporated into the proposed cogeneration facility, represent BACT:

- Dry low NO_x combustion technology on the combustion gas turbines which limits NO_x and CO emissions from the combustion gas turbines to 9.0 ppm,
- SCR technology incorporated in the HRSGs that further reduces total NO_x emissions to a 2.5 ppmvd basis, and
- Oxidation catalyst controls incorporated into the HRSGs that reduce CO emissions to 2.0 ppmvd and VOCs reduced by approximately 30% with the application of the CO oxidation catalyst.

Emissions of Criteria Pollutants

The combustion turbine is an internal combustion turbine with emissions varying with ambient temperature and load condition. Since turbine operating parameters are directly affected by the ambient temperature, the ambient temperatures of 5°F, 50°F, and 85°F are considered in the emission calculations. These temperatures are chosen to represent one winter condition (5°F), an annual average condition (50°F), and one hot summer condition (85°F). Turbine emissions are higher at lower ambient temperatures. For each of these temperatures, three load conditions are considered: 100 (base load), 75, and 50% load. For purposes of establishing the PSD permit emission limits, it is conservatively assumed that the gas turbines will operate 24 hours per day, 7 days per week.

The proposed emission units for the cogeneration facility are as follows:

- Three General Electric Frame 7FA combustion turbines (approximately 1,614 mmBtu/hour lower heating value for each turbine at 50°F and base load conditions),
- One diesel-driven emergency generator, about 1,500 kW in size,

- One diesel-driven firewater pump, about 265 horse power in size, and
- One multi-cell cooling tower.

The following operating scenario was considered as resulting in maximum emissions, and was used as the basis for the proposed permit limits:

- Base load on natural gas with duct burners operating on natural gas at a maximum rate for up to 7,960 hours per year, 50% load for up to 300 hours per year, and 100 hot starts per turbine and shutdowns with the remaining hours offline.
- A mixture of partial load and base load turbine operations (between 50% and base load) could occur for up to 8,760 hours per year. Emissions for partial loads are less than those at base load.
- An emergency diesel generator operating for testing and maintenance purposes for approximately two hours a week on any given day and up to a maximum of 250 hours per year.
- A firewater pump operating for testing and maintenance purposes for approximately two hours a week on any given day and up to a maximum of 250 hours per year.
- A cooling tower (PM₁₀ only) operating at peak capacity 24 hours per day, 7 days per week, 52 weeks per year.

Hourly criteria pollutant emission rates from auxiliary equipment such as the cooling tower, emergency diesel generator, and the emergency firewater pump are shown in Table 3.2-6.

Table 3.2-6: Hourly Criteria Pollutant Emission Rates – Auxiliary Equipment

Operating Unit	Hourly Emissions (lbs/hr)				
	NO _x	CO	VOC	PM ₁₀	SO ₂
Emergency generator	27.5	6.9	1.3	0.7	0.80
Firewater pump	3.33	0.17	0.14	0.05	0.105
Cooling tower	NE	NE	NE	1.63	NE

Source: BP 2002

NE = no emissions

Annual maximum potential emissions from the cogeneration facility and the auxiliary equipment are shown in Table 3.2-7.

Table 3.2-7: Annual Maximum Potential Criteria Pollutant Emissions

Operating Unit	Annual Emissions (tons/year)				
	NO _x	CO	VOC	PM ₁₀	SO ₂
Cogeneration Facility Turbines	229.4	156.8	42.2	254.4	50.9
Emergency generator	3.4	0.9	0.16	0.09	0.0995
Firewater pump	0.42	0.021	0.018	0.006	0.0131
Cooling tower	NE	NE	NE	7.1	NE
Total	233.3	157.7	42.3	261.6	51.0

Source: BP 2002

NE = no emissions

Note: Totals may not equal sum of individual components due to rounding. Refinery emissions reductions are excluded.

PSD Air Quality Impact Assessment

For purposes of the PSD assessments described below, emissions for the cogeneration facility were considered without taking into account any emission reductions that would occur at the refinery following removal of existing steam boilers.

PSD regulations require an assessment of the project's impact on air quality related values (AQRV) in Class I areas. AQRVs include regional visibility or haze; the effects of primary and secondary pollutants on sensitive plants; the effects of pollutant deposition on soils and water bodies; and effects associated with secondary aerosol formation. These requirements provide special protection for Class I areas.

Class I areas within a 124-mile radius of the project site include: North Cascades National Park, Olympic National Park, Glacier Peak Wilderness Area, Alpine Lakes Wilderness Area, and Pasayten Wilderness Area. The Mt. Baker Wilderness area was also included for informational purposes, even though it is not afforded special protection under the Clean Air Act.

PSD Class II Increment Consumption Analysis

Table 3.2-8 summarizes the maximum concentrations resulting from the cogeneration facility, and locations where these maxima were reached. Except for the Annual SO₂ concentration, all locations are in Whatcom County within 1-mile (or closer) of the site.

Table 3.2-8: Maximum Concentrations ¹

Pollutant	Averaging Time	Conc. (ug/m3)	Location
SO ₂	ANNUAL	0.03	7.5-miles north of project on the US/Canada border
SO ₂	24-HR	1.0	328-feet north of the project site
SO ₂	3-HR	5.0	Eastern boundary of the project site
SO ₂	1-HR	8.7	Eastern boundary of the project site
PM ₁₀	ANNUAL	0.25	1 mile north of the project site
PM ₁₀	24-HR	4.3	328 feet north of the project site
PM _{2.5}	ANNUAL	0.25	1 mile north of the project site
PM _{2.5}	24-HR	4.3	328 feet north of the project site
CO	8-HR	12.6	Eastern boundary of the project site
CO	1-HR	67.3	Eastern boundary of the project site
NO _X	ANNUAL	0.60	Northern boundary of the project site

¹ Not including background concentrations

The maximum modeled concentrations of SO₂, NO₂, CO, and PM₁₀ including background are below the respective SILs (Table 3.2-9). Proposed project generation of these pollutants has an insignificant impact on Class II increments, so further analysis is not required. In fact, Table 3.2-11 demonstrates that emissions combined with background concentrations are anticipated to be below the most stringent regulation for each criteria pollutant analyzed. The project would comply with the PSD Class II increment limits.

Local Air Quality Impact Assessment

The assessment of impacts on local and regional ambient air quality from the proposed facility was conducted using EPA-approved air quality dispersion models. These models are based on fundamental mathematical descriptions of atmospheric processes in which a pollutant source can be related to a receptor area. These models evaluated compliance with state and federal ambient air quality standards; SILs; and Class II area increments for NO₂ and SO₂. The regional impact assessment evaluated potential impacts on Class I areas within about 124 miles of the project site, including impacts on visibility, Class I increments for NO₂, SO₂, and PM₁₀, and impacts on soil and vegetation from deposition of nitrogen and sulfur compounds.

The Industrial Source Complex (ISC) dispersion model (EPA SCRAM) was used. The modeling analysis revealed that the project would not significantly affect the ambient air quality of the area, nor have a significant effect on Class II areas. Table 3.2-9 compares maximum concentrations to the PSD SIL.

Table 3.2-9: Significant Impact Level Modeling Analysis Results – U.S. Class II Areas¹

Pollutant	Averaging Period	Maximum Concentration ^{2,3} (µg/m ³)	SIL ⁴ (µg/m ³)
Sulfur dioxide	annual ^{5,7}	0.03	1
	24-hour ^{6,8}	4.3	5
	three-hour ^{6,8}	8.4	25
Inhalable particulate (PM ₁₀) ³	annual ⁷	0.25	1
	24-hour	4.3	5
Carbon monoxide	eight-hour ⁸	50.4	500
	one-hour ⁸	81.4	2,000
Nitrogen dioxide	annual ⁷	0.60	1

1 All other areas that are not designated as Class I within the State of Washington.

2 Highest of all cases for 1995, 1996, 1998, 1999, 2000.

3 Excludes the effect of refinery emission reductions.

4 Significant impact level for criteria pollutants.

5 Value represents a maximum sulfur content in natural gas of 0.8 gr/100 standard cubic feet annual average.

6 Value represents a maximum sulfur content in natural gas of 1.6 gr/100 standard cubic feet.

7 Based on annual average ambient temperature of 50°F.

8 From emergency use of the diesel generator.

Table 3.2-10 shows the results of the long-term criteria pollutant modeling. The maximum long-term (annual average) ground-level concentrations for criteria pollutants (NO₂, SO₂, and PM₁₀) were modeled using the ISC model.

Background concentrations are the maximum value for each pollutant and averaging time of the two nearest representative ambient measuring stations. The predicted concentrations are added to the maximum background concentrations and compared to the most stringent NAAQS or the WAAQS shown in Table 3.2-1. Table 3.2-11 shows that the total concentration (modeled concentration plus background concentration) is significantly less than the most stringent standard for all pollutants analyzed.

Table 3.2-10: Significant Impact Level and Modeling Analysis Results - Class I Areas¹

Pollutant	Averaging Period	Maximum Concentration ^{2,3} ($\mu\text{g}/\text{m}^3$)	SIL ⁴ ($\mu\text{g}/\text{m}^3$)
Sulfur Dioxide	annual	0.001	0.1
	24-hour	0.021	0.2
	three-hour	0.048	1
PM ₁₀	annual	0.0054	0.2
	24-hour	0.087	0.3
Nitrogen dioxide	annual	0.0053	0.1

1 Class I areas include North Cascades National Park, Olympic National Park, Glacier Peak Wilderness, Alpine Lakes Wilderness, and Pasayten Wilderness Area.

2 Highest of 1995, 1996, 1998, 1999, 2000.

3 Excludes the effect of refinery emissions reductions.

4 Significant impact level for criteria pollutants.

Table 3.2-11: Comparison with Ambient Air Quality Standards

Pollutant	Averaging Time	Maximum Concentration ($\mu\text{g}/\text{m}^3$)			Most Stringent of the State of Washington Standards or NAAQS ($\mu\text{g}/\text{m}^3$)
		Modeled	Background	Total	
SO ₂	annual	0.03	3	3	80
	24-hour	1.0	13	14	365
	three-hour	5.1	27	32	1,300
	one-hour	8.7	35	44	1,065
PM ₁₀	annual	0.25	13	13	50
	24-hour	4.3	35	39	150
PM _{2.5}	annual	0.25	9	9	15
	24-hour	4.3	29	33	65
CO	eight-hour	12.6	2,668	2,681	10,000
	one-hour	67.3	2,900	2,967	40,000
NO ₂	annual	0.60	27	28	100

Source: BP 2002

Excludes the effect of refinery emissions reductions.

All PM₁₀ was conservatively assumed to be PM_{2.5}.

Pollutant Concentration Effects on Soils and Vegetation

Federal land managers (National Park Service, U.S. Fish and Wildlife, and U.S. Forest Service) have the responsibility of ensuring AQRVs in Class I areas are not adversely affected, regardless of whether the Class I increments are maintained. In order to protect plant species, the U.S. Forest Service recommends that maximum SO₂ concentrations not exceed 40 to 50 parts per billion (ppb) (105 to 130 $\mu\text{g}/\text{m}^3$), and annual SO₂ concentrations should not exceed 8 to 12 ppb (21 to 31 $\mu\text{g}/\text{m}^3$). For emissions of NO₂ (assuming a full conversion from NO_x), potential plant damage would not begin to occur with 24-hour concentrations less than 15 ppb (28 $\mu\text{g}/\text{m}^3$). Based on the results of the dispersion modeling analyses, facility emissions are expected to have a negligible effect on soils and vegetation. The proposed project would only combust low-sulfur natural gas fuel, thus minimizing the emission of sulfur compounds. Also, modeling results show that the annual maximum annual concentration of NO₂ is below 1.0 $\mu\text{g}/\text{m}^3$ (about 1.1 ppb).

Nitrogen and Sulfur Deposition at Class I Areas

The CALPUFF modeling system was used to estimate the cogeneration facility's potential contribution to total nitrogen and sulfur deposition in Class I areas. Soil, vegetation, and aquatic resources in Class I areas are potentially influenced by nitrogen and sulfur deposition.

A change in visibility of greater than 5% is the threshold (level of concern) used by federal land managers to signify that additional analysis may be needed to more fully understand the overall impacts on visibility. The results of the dispersion modeling for visibility impacts are summarized in Table 3.2-12. Without the reduced emissions associated with decommissioning the boilers, the CALPUFF modeling results show that the maximum change in visibility in a Class I area is 6.0%. The maximum visibility change modeled is in Olympic National Park. Only one day per year was above 5% in all of the modeled Class I areas.

Regional Haze Assessment

Regional haze is usually quantified using two related indicators. First, the “visual range” is the distance at which a dark mountain is just perceptible against the sky. The visual range decreases if the air is polluted. Secondly, the “light extinction coefficient” is used to quantify how pollutants in the atmosphere reduce visual range. Increased light extinction reduces the visual range. According to federal land managers responsible for protecting air quality in Class I areas, a 5% change in extinction can be used to indicate a “just perceptible” change to landscape and a 10% change in extinction coefficient from the “natural” background is considered a significant incremental impact. Section 3.2.6, Cumulative Impacts, contains a more in-depth discussion.

Toxic Air Pollutant Emission Rates

For purposes of the regulatory Toxic Air Pollutant assessments described below, emissions for the cogeneration facility were considered excluding any emission reductions that would occur at the refinery following removal of existing steam generation boilers.

This section presents the emission factors and emission rates used in the analysis of toxic air pollutants. The proposed project has the potential to emit small quantities of toxic air pollutants regulated by Ecology. Formaldehyde, benzene, and other organic compounds associated with the combustion of fossil fuels would be released. In addition, post-combustion control with SCR results in ammonia emissions or “slip” that passes through the process unreacted. Ammonia is not a federal hazardous air pollutant, but it is identified as a Washington State Toxic Air Pollutant and along with sulfuric acid would be the highest noncriteria pollutant concentration emitted from the project.

Emissions of toxic air pollutants would result from the combustion of natural gas in the gas turbines, HRSG duct burners, and auxiliary boiler, as well as from the use of the emergency diesel generator and diesel fire pump. Emissions were computed for short-term emission rates, and the hourly fuel use or heat input was used to estimate emissions on a pounds per hour basis. For the annual average emission rates (tons per year), total annual fuel use or heat inputs were computed and used with the emission factors in estimating the emissions.

Table 3.2-12: Air Quality Modeling Results

Operating Scenario	Class I area	Maximum Nitrogen Deposition (g/ha/yr)	Maximum Sulfur Deposition (g/ha/yr)	Maximum Visibility Change (%)	Number of Days over 5%	Visibility Change when Subtracting Boiler Emission Reductions
Normal operation without duct burners operating	Olympic National Park	0.09	0.11	5.5	1	1.6
	North Cascades National Park	0.44	0.31	2.5	0	1.4
	Alpine Lakes Wilderness Area	0.56	0.68	3.8	0	1.9
	Glacier Peak Wilderness Area	0.42	0.32	4.1	0	1.8
	Pasayten Wilderness Area	0.23	0.13	1.7	0	1.0
Normal operation with duct burners	Mt. Baker Wilderness Area	0.63	0.56	4.0	0	2.2
	Olympic National Park	0.09	0.11	5.6	1	1.7
	North Cascades National Park	0.45	0.31	2.5	0	1.4
	Alpine Lakes Wilderness Area	0.57	0.70	3.9	0	2.0
	Glacier Peak Wilderness Area	0.42	0.32	4.2	0	1.9
Operation with duct burners firing at a maximum rate	Pasayten Wilderness Area	0.23	0.13	1.7	0	1.1
	Mt. Baker Wilderness Area	0.64	0.57	4.0	0	2.3
	Olympic National Park	0.09	0.12	6.0	1	1.9
	North Cascades National Park	0.47	0.32	2.6	0	1.5
	Alpine Lakes Wilderness Area	0.60	0.73	4.1	0	2.3
Maximum	Glacier Peak Wilderness Area	0.44	0.34	4.4	0	2.1
	Pasayten Wilderness Area	0.24	0.14	1.8	0	1.2
	Mt. Baker Wilderness Area	0.67	0.60	4.1	0	2.3
Maximum		0.67	0.73	6.0	1	2.3

Notes: Significance level for visibility change is 5%.

Significance level for deposition is 5 g/ha/yr.

Ammonia emissions are based on a 5 ppmvd slip associated with the use of SCR for NO_x control. Sulfuric acid mist emissions depend on the amount of sulfur in the fuel and amount of sulfur dioxide converted to sulfur trioxide.

The toxic air pollutants and their pollutant class, emission factors, and emission rates for the gas turbines, the emergency diesel generator, and the diesel fire pump are listed in Table 3.2-13. The toxic air pollutant classes refer to Class A, for annual-averaged risk-based carcinogens, and Class B for non-carcinogens.

The proposed project would adopt BACT for toxics for controlling toxic emissions pursuant to Chapter 173-460-040 WAC, including the following:

- Use of clean natural gas as the only fuel for the combustion gas turbines and HRSG duct burners which help minimize formation of toxics, and
- Use of an oxidation catalyst unit on each HRSG duct burner that would reduce the emissions of certain volatile organic toxic compounds.

Modeling Criteria

Air quality dispersion modeling was used to assess compliance with the State of Washington's toxic air pollutant regulations (Chapter 173-460 WAC). Those toxic air pollutants that are emitted in quantities above the Small Quantity Emissions Rate (SQER) require calculation of potential impacts that are then compared with the Acceptable Source Impact Levels (ASILs) to assess compliance. Seventeen compounds were identified as being emitted in amounts greater than the small quantity emission rate and required modeling. Depending on the compound, either the 24-hour or annual average concentrations were used for comparison with the ASILs.

Toxic Air Pollutant Analysis

The maximum modeled 24-hour and annual average toxic air pollutant concentrations resulting from the proposed facility emissions are compared to the appropriate ASILs in Table 3.2-14. For all toxic air pollutants evaluated, the maximum modeled concentrations are less than the ASILs. Maximum short-term ammonia and sulfuric acid mist concentrations are also below the 24-hour ASIL. Based on these modeling results, the proposed cogeneration facility is not expected to create any significant impacts due to its toxic air pollutant emissions.

Table 3.2-13: Toxic Compounds that Require Modeling

Toxic Compound	Emission Rate for three Combustion Turbines (lbs/hr)	Emission Rate for Emergency Generator (lbs/hr)	Emission Rate for Firewater Pump (lbs/hr)	Total Annual Emissions (lbs/yr)	Total Hourly Emissions (lbs/hr)	SQER (lbs/yr)	SQER (lbs/hr)	ASIL (µg/m ³)	Class A or B Toxic Compound
Acetaldehyde	0.0210	0.00039	0.001553	184.8	0.023	50	NA	0.45	A Annual
Acrolein	0.0373	0.000121	0.0001872	327.1	0.038	175	0.02	0.02	B 24-hr
Ammonia ¹	39.5	0	0	346,247	39.5	17,500	2.0	100	B 24-hr
Benzene	0.0705	0.01192	0.001889	621.4	0.084	20	NA	0.12	A Annual
1,3-Butadiene	0.0025	0	0.0000791	22.0	0.0026	0.5	NA	0.0036	A Annual
Formaldehyde	0.5876	0.00121	0.000239	5,148	0.59	20	NA	0.077	A Annual
PAH	0.0129	0.00326	0.000034	113.5	0.016	NA	NA	0.00048	A Annual
Arsenic	0.000052	0.00371	0.000265	1.5	0.00403	NA	NA	0.00023	A Annual
Beryllium	0.000003	0	0	0.03	0.000003	NA	NA	0.00042	A Annual
Cadmium	0.000287	0.00035	0.000025	2.6	0.00066	NA	NA	0.00056	A Annual
Chromium	0.0259	0.00371	0.000265	227.6	0.030	175	0.02	1.7	B 24-hr
Cobalt	0.0255	0	0	223.6	0.026	175	0.02	0.33	B 24-hr
Copper ¹	0.0257	0	0	225.3	0.026	175	0.02	0.3	B 24-hr
Manganese	0.0256	0	0	224.2	0.026	175	0.02	0.4	B 24-hr
Nickel	0.0260	0.00035	0.000025	228.3	0.026	0.5	NA	0.0021	A Annual
Zinc ¹	0.0331	0.00385	0.000275	290.7	0.037	175	0.02	7	B 24-hr
Sulfuric Acid ¹	8.1	0.2437	0.0321	71,040	8.38	175	0.02	3.3	B 24-hr

Notes: SQER = Small Quantity Emission Rate

ASIL = Acceptable Source Impact Level

NA = Not Applicable

The results represent maximum emissions

1 Not an EPA classified hazardous air pollutant.

Table 3.2-14: Significant Impact Level Modeling Analysis Results - Toxic Compounds

Pollutant	Maximum Predicted Concentration ($\mu\text{g}/\text{m}^3$) ⁴		ASIL ($\mu\text{g}/\text{m}^3$) ³	ASIL Exceeded
	Annual ¹	24-hr ²		
Acetaldehyde	0.00014	NA	0.45	No
Acrolein	NA	0.0027	0.02	No
Ammonia	NA	2.8	100	No
Benzene	0.00032	NA	0.12	No
1,3-Butadiene	0.00001	NA	0.0036	No
Formaldehyde	0.00237	NA	0.077	No
PAH	0.00007	NA	0.00048	No
Arsenic	0.00007	NA	0.00023	No
Beryllium	<0.00001 ⁵	NA	0.00042	No
Cadmium	0.00001	NA	0.00056	No
Chromium	NA	0.0024	1.7	No
Cobalt	NA	0.0018	0.33	No
Copper	NA	0.0018	0.3	No
Manganese	NA	0.0018	0.4	No
Nickel	0.00011	NA	0.0021	No
Zinc	NA	0.0025	7	No
Sulfuric Acid	NA	0.57	3.3	No

1 Highest of cases (modeled operating scenarios) 1AB, 1BB, 1CB, 2B, 6B (50°F).

2 Highest of all cases (modeled operating scenarios) for 1995, 1996, 1998, 1999, and 2000.

3 Acceptable source impact levels.

4 Excludes the effect of refinery emissions reductions.

5 Impacts are less than the sensitivity of the ISC model of 0.00001 $\mu\text{g}/\text{m}^3$

Regional Air Quality Impact Assessment

Short Range Air Quality Impacts in Canada

Concentration analyses for areas in Canada were conducted using methods similar to those used for Class II areas in the U.S., as previously described. These analyses excluded any emission reductions from the refinery resulting from the removal of refinery boilers.

The analyses covered an area into Canada extending 31-miles from the project site (the limit of the approved use of the ISC dispersion model), as shown in Figure 3.2-1. The predicted concentrations are added to the maximum background concentrations provided by Canadian regulatory agencies and compared to the Canadian objectives and standards presented in Table 3.2-15. The $\text{PM}_{2.5}$ emissions are not specifically modeled and are conservatively assumed to be equal to the PM_{10} emissions. In reality, the $\text{PM}_{2.5}$ emissions are a subset of the PM_{10} emissions and should, therefore, be lower than reported. The modeled maximum concentration is significantly less than the background concentration for all pollutants. The total concentration (modeled concentration plus background concentration) is significantly less than the objectives and standards (Table 3.2-2) for all pollutants.

Table 3.2-16 summarizes the concentrations resulting from the project alone (not including background) reached in Canada. The highest concentrations in Canada were reached 7.5 to 7.8 miles north of the project site at the US/Canada border. As discussed above, the maximum

modeled concentration (including background) occurs in the US, and is less than both the US standards and Canadian Objectives. Table 3.2-17 summarizes the concentrations estimated (including background) at the closest monitoring stations in Canada.

Table 3.2-15: Maximum Concentration Modeling Analysis in Canada

Pollutant	Averaging Time	Maximum Concentration in Canada ($\mu\text{g}/\text{m}^3$)			Most Stringent Canadian Objective or Standard ($\mu\text{g}/\text{m}^3$)
		Modeled	Background	Total	
SO ₂	annual	0.03	3	3	25
	24-hour	0.7	16	17	150
	three-hour	3.3	27	30	374
	one-hour	5.3	59	64	450
PM ₁₀	annual	0.2	13	13	30
	24-hour	2.5	35	38	50
PM _{2.5} ^{1, 2}	24-hour	0.9	18	19	30
CO	eight-hour	4.8	2,668	2,673	5,500
	one-hour	13.6	2,900	2,914	14,300
NO ₂ ³	annual	0.2	27	27	60
	24-hour	1.6	69	71	200
	one-hour	16.7	107	124	400

Notes: Excludes the effect of refinery emissions reductions.

1 PM_{2.5} emissions are conservatively assumed to be equal to PM₁₀ emissions.

2 The PM_{2.5} Canada-wide standard is based on the 98th percentile averaged over three years; therefore, the modeled and background values indicated above are also based on these assumptions.

3 NO_x is considered to be fully converted to NO₂.

Table 3.2-16: Highest Concentrations in Canada

Pollutant	Averaging Time	Concentration ($\mu\text{g}/\text{m}^3$)	Location
SO ₂	ANNUAL	0.03	7.5-miles north of project on the US/Canada border
SO ₂	24-HR	0.7	7.5-miles north of project on the US/Canada border
SO ₂	3-HR	3.3	7.5-miles north of project on the US/Canada border
SO ₂	1-HR	5.3	7.5-miles north of project on the US/Canada border
PM ₁₀	ANNUAL	0.2	7.5-miles north of project on the US/Canada border
PM ₁₀	24-HR	2.5	7.5-miles north of project on the US/Canada border
PM _{2.5}	24-HR	0.9	7.5-miles north of project on the US/Canada border
CO	8-HR	4.8	7.8-miles north of project on the US/Canada border
CO	1-HR	13.6	7.5-miles north of project on the US/Canada border
NO _x	ANNUAL	0.2	7.5-miles north of project on the US/Canada border
NO _x	24-HR	1.6	7.5-miles north of project on the US/Canada border
NO _x	1-HR	16.7	7.5-miles north of project on the US/Canada border

Table 3.2-17: Ambient Air Monitors Closest to Project Site

Pollutant	Averaging Time	Concentration (µg/m3)	Background Concentration (µg/m3)	Total Concentration (µg/m3)	Objective ¹ (µg/m3)
Concentrations at Surrey					
PM10	ANNUAL	0.05	13	13.0	30
PM10	24-HR	0.50	39	39.5	50
NOX	ANNUAL	0.04	27	27.0	60
NOX	24-HR	0.42	69	69.4	200
NOX	1-HR	8.2	107	115	400
CO	8-HR	1.1	2436	2437	5500
CO	1-HR	3.6	2900	2904	14300
Concentrations at Langley ²					
PM10	ANNUAL	0.04	13	13.0	30
PM10	24-HR	0.36	37	37.4	50
PM2.52	24-HR	0.36	16	16.4	30
NOX	ANNUAL	0.03	20	20.0	60
NOX	24-HR	0.33	52	52.3	200
NOX	1-HR	7.8	92	100	400
CO	8-HR	0.7	2668	2669	5500
CO	1-HR	3.6	4060	4064	14300
Closest SO2 monitors in Canada – Concentrations at Richmond					
SO2	ANNUAL	0.003	3	3.0	25
SO2	24-HR	0.08	13	13.1	150
SO2	3-HR	0.34	27	27.3	374
SO2	1-HR	0.90	35	35.9	450
Concentrations at Abbotsford					
SO2	ANNUAL	0.0014	3	3.0	25
SO2	24-HR	0.058	8	8.1	150
SO2	3-HR	0.35	21	21.3	374
SO2	1-HR	1.04	29	30.0	450
PM2.5 Ambient Air Monitors Closest to Project Site – Concentrations at Pitt Meadows ³					
PM2.5	ANNUAL	0.029	9	9.0	NA
PM2.5	24-HR	0.30	19	19.3	30
Concentrations at Vancouver Airport					
PM2.5	ANNUAL	0.016	9	9.0	NA
PM2.5	24-HR	0.17	18	18.2	30

- Notes: 1 Most Stringent Canadian Objective or Standard
2 A PM2.5 monitor was added at Langley in 2002.
3 PM2.5 background and total concentration are based on the 98th percentile

Air Quality Visibility Analysis in Canada

The visibility analyses for Canadian areas were conducted using methods similar to those used for Class I areas in the U.S., and excluded any effects of refinery emission reductions. The analyses were conducted along seven lines of sight recommended by the GVRD (listed in Table 3.2-18). The visibility extinction was averaged along each line of sight to achieve a day-by-day account of whether visibility is impaired with and without the impacts from the proposed project. The maximum visibility change because of emissions from the proposed project was also calculated.

The results of the Canada visibility analyses are summarized in Table 3.2-19. A visual range of less than 37 miles was used to determine impaired visibility. As shown in this table, impacts from the proposed project would not increase the number of days with impaired visibility at any of the seven specified lines of sight. A visibility analysis threshold has not been established by Canadian agencies. For purposes of this analysis, the threshold established by the U.S. federal land managers was used. According to the federal land managers, a greater than 5% change in visibility will evoke a noticeable change in most landscapes. The results of the visibility analysis in Canada show that the maximum visibility change is only 2.7%, which is significantly below the 5% threshold.

Table 3.2-18: Lines of Sight Evaluated for Visibility Analysis in Canada

Line of Sight	Observer Location	Direction and Target
1	Victoria	East-northeast to Mount Baker
2	White Rock	East-southeast to Mount Baker
3	Tsawassen	East-southeast to Mount Baker
4	Vancouver	North to North Shore Mountains (The Lions)
5	Langley	North to North Shore Mountains (Golden Ears)
6	Chilliwack	East to Mount Cheam
7	Abbotsford	Southeast to Mount Baker

Table 3.2-19: Results of Visibility Analysis in Canada

Line of Sight	Number of Days with Impaired Visibility, Background Conditions ¹	Additional Days with Impaired Visibility from Cogeneration Facility	Maximum Visibility Change
1	171	0	1.2%
2	166	0	2.4%
3	166	0	2.1%
4	166	0	2.2%
5	166	0	2.7%
6	166	0	1.5%
7	166	0	1.4%

¹ Impaired visibility is defined as those days with a visibility range of less than 37-miles. Excludes the effect of refinery emissions reductions.

Regional Impacts of Concurrent Emissions Reductions at the Refinery

State regulatory air permitting requirements require that the maximum potential emissions expected from the cogeneration facility be used for permitting purposes. The analyses presented above are based on the maximum potential emissions. However, in order to characterize a scenario of more probable long range impacts to the region, the Applicant has estimated what the actual emissions from the cogeneration facility are likely to be. This estimate is based on the following assumptions, described in more detail below:

- Refinery emissions would decrease because of the removal of existing utility boilers that would no longer be needed once steam was purchased from the cogeneration facility;

- A more realistic actual operating scenario would lead to actual emissions lower than the maximum potential emissions required by regulatory analyses;
- Actual particulate emissions would be lower than those measured at the stacks by the required EPA reference methods; and
- Recent information indicates that long range secondary particulate formation would be reduced due to NO_x emission reductions at the refinery.

The overall emissions reductions estimated by the Applicant are summarized in Table 3.2-20.

Table 3.2-20: Overall Emission Reductions Estimated by the Applicant

Expected Annual Reductions (tpy)	NO _x	CO	VOC	PM ₁₀	SO ₂
Estimated Actual Emissions from the Cogeneration Facility	181	81	28	94	50
Refinery Emission Reductions Through Utility Boiler Removal	-499	-54	-3	-10	-7
Net Regional Change in Emissions	-318	27	25	-84	43
Changes in Secondary Emissions from Cogeneration Facility and Refinery Boiler Removal	105	0	0	-96	-9
Net Regional Emission Changes	-213	27	25	-12	34

Source: BP 2002

Refinery Emission Reductions due to removal of Refinery Steam Boilers

Emissions of criteria pollutants from the proposed cogeneration facility would be offset by reductions in emissions from the refinery. These reductions would occur because the cogeneration facility would provide steam to the refinery, which would allow the refinery to discontinue the utility boilers currently in use. This would also allow the refinery to reduce its use of gas-fired heaters. Table 3.2-21 summarizes the possible refinery emission reductions if steam produced by the cogeneration project replaces steam currently produced by refinery boilers. A consequence of cogeneration is the reduction in steam production inside the refinery and an associated reduction in the criteria pollutant emissions. All emission reductions are based on the reduction in steam production in the refinery. After the cogeneration project begins supplying steam to the refinery, the refinery utility boilers would be shut down and would no longer produce emissions.

It should be noted that new boilers are being planned for the Clean Fuels project but they will be shut down when the cogeneration facility is operating. Some backup boiler capability would still be required at the refinery when the cogeneration facility is not operating.

Table 3.2-21: Refinery Emission Reductions

Expected Annual Reductions (tpy)	NO _x	CO	VOC	PM ₁₀	SO ₂
Refinery emission reductions	-499	-54	-3	-10	-7

Source: BP 2002

Estimate of Actual Emissions from the Cogeneration Facility

The data in Table 3.2-7 reflects the maximum potential emissions expected from the cogeneration facility, based on the regulatory requirements of PSD and NSR review. The Applicant has also prepared an estimate of the cogeneration facility emissions based on what expected actual operation of the cogeneration are likely to be, shown in Table 3.2-22. This estimate was based upon several assumptions. First, the Applicant used an average operating scenario that was developed based on six years of expected operation (a typical operational/maintenance cycle for turbines) while taking into account market conditions and required maintenance. Under this average operating scenario, the cogeneration facility is expected to operate as follows:

- 55% of the time at 100% turbine load and no duct firing.
- 39% of the time at 100% turbine load and variable duct burner firing sufficient to maintain the refinery steam header pressure.
- 2% of the time in a forced outage where one turbine is down for maintenance for eight hours while the other two are operating at 100% turbine load.
- 1% of the time in an economic dispatch mode where all three turbines are down for eight hours.
- 3% of the time in a planned outage where turbines would be shut down for more than 72 hours for planned maintenance.

Table 3.2-22: Expected Annual Emissions (Criteria Pollutants)

Expected Annual Emissions (tons/year)	NO _x	CO	VOC	PM ₁₀	SO ₂
100% load with no duct firing	104.9	45.8	14.4	133.0	27.7
100% load with minimal duct firing	65.7	28.2	11.6	95.2	20.4
Forced outage	3.9	2.8	0.7	4.6	0.9
Economic dispatch	2.3	2.9	0.5	2.3	0.4
Planned outage	0.4	0.6	0.1	0.1	0.02
Emergency generator	3.44	0.86	0.16	0.09	0.10
Firewater pump	0.42	0.021	0.018	0.006	0.013
Cooling tower	NE	NE	NE	7.1	NE
Total (tons/year)	181.1	81.2	27.5	242.4	49.6
PM ₁₀ adjustments ¹				-148.5	
Total (tons/year)				93.9	

NE - no emissions

¹ Approximately 60% of the PM₁₀ emissions are subtracted due to source tests exaggerations of sulfates and the inclusion of compounds associated with background, ambient air.

Second, the Applicant assumed that average actual NO_x emissions would be no more than 90% of the proposed permit limit. In order to ensure constant compliance with the short-term permit limits, these types of facilities would expect to maintain average emissions somewhat below their permit limits. Based on its operating experience, the Applicant indicated that it would be reasonable to expect actual NO_x emissions to average 10% below the permit limit.

Third, the Applicant assumed that average actual CO emissions would be no more than 80% of the proposed permit limit in order to ensure constant compliance with the short-term permit limits. Since oxidation catalyst performance is more efficient when new and degrades over time, it is reasonable to expect that the CO concentration will be very low initially and then increase over time. The long-term average CO concentration will always be below the permit limit.

Finally, the Applicant assumed that the project's actual PM₁₀ emissions would be approximately 60% below the proposed permit limit due to source test exaggeration of sulfates and the inclusion of compounds associated with background air. The Applicant based these assumptions on research that has been conducted in an effort to determine the source and type of the particulate matter in the exhaust gas and to determine whether the EPA test method is accurate (England and Wien 2002).

This research shows that up to 90% of the particulate reported by this test method (EPA Method PRE-4/202) in exhaust from natural gas-fueled combustion turbines is condensable particulate. Of this condensable particulate, about 90% is inorganic and comprised of sulfates, chlorides, ammonia, sodium, and calcium.

This research also shows that the EPA test method significantly exaggerates PM₁₀ emissions. By far, the largest source of error in the EPA test method is generated by condensable particulate measured by the test. SO₂ gas, a constituent of the stack gas, is drawn into the test apparatus. As expected of a gas, SO₂ passes through the filterable portion of the test apparatus and into an ice water bath, where it is “bubbled” through the cold water. The SO₂ dissolves in the cold water. Since gas turbines operate with a large excess of oxygen, oxygen is also dissolved in the cold water. During the testing, virtually all of the SO₂ is slowly oxidized to form sulfate (SO₄), which is measured as a particulate. This results in the test method significantly overestimating the particulate emissions because, during normal operation, only a relatively small portion of the SO₂ in the exhaust would form SO₄ in the stack.

The test method also overstates the particulate emissions by including particulate already present in the ambient air. This particulate matter was identified in the research as sodium, chloride, and calcium.

The study concludes that the EPA test method suffers from measurement error due to the small amount of particulate sample collected from the gas turbine exhaust. The EPA method was intended to collect samples over a one-hour period, however, the research shows that gas turbine tests must be run for up to six hours to collect enough material.

Based on the information contained in the GE and Sierra Research studies, the actual particulate emissions from the facility are expected to be at least 60% less than the particulate emissions measured by the EPA reference method test.

Secondary Particulate

The Applicant also considered secondary particulate in the overall particulate emissions balance. The projected annual emissions shown in Table 3.2-22 are based only on in-stack emission or primary emissions.

One to two days after leaving the stack, a portion of the NO₂ and SO₂ emitted from the stack as gas eventually combines with ammonia in the atmosphere to form particles of ammonium nitrate and ammonium sulfate. These newly formed compounds are called secondary particulate because they are formed in the atmosphere outside of the stack.

The amount of NO₂ and SO₂ converted to particulate is dependent on a number of atmospheric factors, including time, temperature, and moisture. In the following analysis, the 33% of NO₂ is converted to ammonium nitrate and 20% of SO₂ is converted to ammonium sulfate. The conversion factors used for this analysis are consistent with the CALPUFF model conversion factors and published articles (Stockwell 2000).

As shown in Table 3.2-23, changes in secondary particulate emissions would occur from two sources: first, NO_x and SO₂ emitted by the Cogeneration Facility would produce secondary particulate emissions; second, reductions of NO_x emissions from the Refinery through removal of the utility boilers would lead to a reduction of refinery secondary particulate emissions. When both of these secondary particulate emission changes are taken into account, the proposed project would result in an overall regional reduction of NO_x and particulate, as shown in Table 3.2-20.

Impacts on Class I Visibility Analyses from Refinery Emission Reductions

The Applicant performed additional modeling for the Class I visibility analysis to account for some of the reduction in emissions resulting from removal of the utility boilers at the refinery. The results of this revised dispersion modeling for visibility impacts are summarized in Table 3.2-24. The maximum visibility change, when subtracting the emissions for the three utility boilers, is 2.3%, and the number of days of impact to the Olympic Regional Park is reduced to zero.

Table 3.2-23: Secondary Particulate Emission Balance

Expected Annual Emissions (tons/yr)	NO _x	CO	VOC	PM ₁₀	SO ₂
Total from Cogeneration	181	81	28	94	50
Secondary PM formed by Cogen NO _x and SO ₂	-60	0	0	70	-10
Cogen Emissions After Secondary PM Formation	121	81	28	164	40
Refinery Emission Reductions through utility boiler removal	-499	-54	-3	-10	-7
Secondary PM Avoided by Refinery Reductions	165	0	0	-166	1
Refinery Emission Reductions After Secondary PM Formation	-334	-54	-3	-176	-6
Changes in Secondary emissions from Cogen and removal of Refinery boilers	105	0	0	-96	-9

Source: BP 2002

Note: These balances assume that no molecular weight change occurs upon formation of secondary particulate matter. This is a conservative approach for calculating reduction in PM.

Table 3.2-24: Air Quality Related Values Modeling Analysis Results Including Refinery Emissions Reductions

Operating Scenario	Class I area	Visibility Change when Subtracting Boiler Emission Reductions	Number of Days over 5%
Normal operation without duct burners operating	Olympic National Park	1.6	0
	North Cascades National Park	1.4	0
	Alpine Lakes Wilderness Area	1.9	0
	Glacier Peak Wilderness Area	1.8	0
	Pasayten Wilderness Area	1.0	0
	Mt. Baker Wilderness Area	2.2	0
Normal operation with duct burners	Olympic National Park	1.7	0
	North Cascades National Park	1.4	0
	Alpine Lakes Wilderness Area	2.0	0
	Glacier Peak Wilderness Area	1.9	0
	Pasayten Wilderness Area	1.1	0
	Mt. Baker Wilderness Area	2.3	0
Operation with duct burners firing at a maximum rate	Olympic National Park	1.9	0
	North Cascades National Park	1.5	0
	Alpine Lakes Wilderness Area	2.3	0
	Glacier Peak Wilderness Area	2.1	0
	Pasayten Wilderness Area	1.2	0
	Mt. Baker Wilderness Area	2.3	0
Maximum		2.3	0

Notes: Significance level for visibility change is 5%.

Significance level for deposition is 5 g/ha/yr.

Dust

Onsite roads and parking areas would be constructed with asphalt over a compacted subbase. These roads would be paved to minimize the potential for fugitive dust emissions from vehicle traffic. Significant quantities of dust would not be generated during operation of the proposed facility.

Odors

Operation of the proposed facility is not anticipated to create any nuisance odors. Natural gas may be odorized, but it would be contained within the natural gas pipeline and cogeneration facility piping system up to the point of use in the combustion gas turbines and HRSGs where it would be combusted.

Anhydrous ammonia would be used in the SCR system as a reaction agent for the control of NO_x emissions. Unreacted ammonia would be present in the HRSG exhaust gas flow. Ammonia is commonly perceived as having an odor (e.g., household cleaners). However, based on the quantity to be released through the HRSG stack, ammonia odor is not expected to be detectable. In fact, the dispersion modeling conducted for ammonia at a rate of 5 ppm (a maximum of 13.2 lbs/hour per turbine and about 173 tons/year total) from the HRSG stacks indicates that the public exposure to ammonia (approximately 2.8 g/m³ or 0.004 ppm) would be well below the

range of detection (5 to 53 ppm) (Clayton 1993). Ammonia emissions would be limited to a 24-hour average of no more than 5 ppm at 15% O₂. Relative to the public health exposure of ammonia, the maximum projected ground-level impact of the ammonia emissions, based on the 5 ppm level, is about 3% of the 100 µg/m³ 24-hour health-based standard identified in WAC 173-460.

Cooling Tower Steam Plume Fogging and Icing

In cold weather, a cooling tower plume would typically persist until the air exiting the cooling tower sufficiently mixes with the surrounding cooler, drier air. If the plume returns to ground level prior to dissipating, it can cause localized fogging or icing of downwind structures and roadways.

Downwind impacts caused by water vapor and water droplets from the cooling towers were modeled by the Applicant using the Seasonal/Annual Cooling Tower Impact Program (SACTIP) computer model. SACTIP calculates the occurrence of elevated visible water plumes and salt deposition, and ground-level fogging and icing. The model simulates downwind dispersion of the steam plumes based on wind data from the local meteorological station and relative humidity data.

The objective of this study was to determine if the cooling tower would contribute to fogging and/or icing on Grandview Road on the north side of the project boundary. The analysis shows that fogging may occur for a total of 2.5 hours a year in the northeast or northwest directions. The area affected by fogging extends from 655 to 1640 feet from the center of the cooling tower. Grandview Road is approximately 1,312-feet in these directions and, therefore, may be affected by the edge of the plume for these few hours of the year.

In order for roadway icing to occur, the cooling tower plume needs to touch down on the road surface, the plume must become condensed, and the temperature of the road surface must be below freezing. However, due to the infrequent occurrence of these conditions, if icing were to occur it would be of short duration.

3.2.4 Impacts of No Action

Under this alternative, existing natural-gas-fired power plants would be more likely to continue operations. No new hydroelectric generating capacity is being added, and the development of nuclear power plants has been halted. Wind and solar power do not have the generating availability needed to meet continuous electricity demand. Fuel cell technologies are being developed, but remain relatively small and expensive. Natural-gas-fired combined-cycle combustion turbine plants would meet the increasing demand for electricity generation. If the proposed cogeneration facility were not built and operated, the refinery and others in the region would use electricity produced by existing sources of generation and new gas-fired combined-cycle power plants.

3.2.5 Greenhouse Gas

Overview

The issue of how emissions from human activities might affect global climate has been the subject of extensive international research over the past several decades. There is now a broad consensus among atmospheric scientists that emissions caused by humans are resulting in a rise in global temperatures, although there is still uncertainty about the magnitude of future impacts and the best approach to mitigate the impacts. Two sets of key research documents have recently been published.

The United Nations Intergovernmental Panel on Climate Change (IPCC) published its most recent set of five-year progress reports summarizing worldwide research on global warming (IPCC 2001). These reports indicated that some level of global warming related to human activity is likely to occur and that there is a significant possibility of severe environmental impacts. Several alternative measures were evaluated to achieve the emission reductions specified by the Kyoto Protocol.

President Bush requested the National Academy of Sciences to provide a brief comprehensive review of the IPCC reports (National Academy of Sciences 2001). The review panel included atmospheric scientists with a range of opinions on future global warming. The National Academy of Sciences review was written in lay terms and focused on addressing several fundamental issues. The panel concurred with most of the findings by the IPCC.

Regulatory Framework

Currently, there are no international, national, Washington State, or local regulations that set numerical limits on greenhouse gas emissions, however the Kyoto Protocol has been established and is discussed below. Within the State of Washington, rules relating to siting energy facilities (WAC 463-42-225, Proposal-emission control) requires an Applicant to demonstrate that highest and best practicable treatment for control of emissions is used for a number of air pollutants, including CO₂. The Washington regulation does not specify how “highest and best practicable treatment” for CO₂ is to be quantified.

Several jurisdictions in the Pacific Northwest have committed to, or require, the mitigation of greenhouse gas emissions, for example:

- The State of Oregon’s target is a 17% reduction compared to the most efficient power plant operating in the United States.
- Seattle City Light’s greenhouse gas program cites a target of 100% elimination of net future increases of greenhouse gas emissions from all new fossil fuel generating stations added to the city’s generating mix (Seattle City Light 2001).
- BC Hydro plans to contract with third-party organizations to procure offsite greenhouse gas projects to offset 50% of the increase in greenhouse gas emissions from two new natural-gas fired electrical generating stations on Vancouver Island, up through the year 2010 (BC Hydro 2001). The year 2010 was specified in the Kyoto Protocol as the date upon which signatory

nations must reduce their greenhouse gas emissions. Presumably, new emission reduction programs enacted in response to the Kyoto Protocol (or similar rules) would take effect after BC Hydro's voluntary offset program expired in 2010.

In Washington State, four approved thermal power projects under EFSEC jurisdiction are required to mitigate greenhouse gas emissions, as follows:

- The Chehalis Power Project is must acquire greenhouse gas offsets for up to 8% of the overall emissions; Chehalis Power would acquire offsets on a ton-for-ton basis from a recognized supplier, such as the Climate Trust, or by participating directly in greenhouse gas mitigation projects;
- The Sumas Energy 2 Generation Facility is required to mitigate CO₂ emissions according to the monetary path of the Oregon Energy Facility Siting Council, at \$0.57 per ton of carbon dioxide, based on a 30-year operating life, with no surcharge for administrative expenses; the approximate \$8.04 million payment would be made in five annual installments starting at the time the facility begins to operate.
- The Satsop Combustion Turbine Project is required to mitigate CO₂ emissions from the facility that exceed 0.675 lb/kWh, at a rate of \$0.57 per ton of CO₂ to be mitigated based upon the facility's maximum potential emissions, and adjusted annually according to the Producer Price Index; 7.5% administrative costs would be paid in addition to the per ton mitigation fee; payments would be made annually for the first 30 years in which the facility operates.
- The Wallula Power Project is required to implement a "Greenhouse Gas, Environmental Mitigation Enhancement Package" which includes payment of approximately \$6.0 million to non profit and tribal organizations committed to the development of renewable energy resources and projects, and/or preservation and restoration of fish and wildlife habitat and other environmental programs benefiting the Walla Walla region.

Project Greenhouse Gas Emissions

The significant portion of greenhouse gas emissions generated by the project would result from the combustion of natural gas, a fossil fuel in the Cogeneration facility. For purposes of evaluating greenhouse gas emissions, the combustion efficiency of the proposal is quantified by the CO₂ emission factor, with units of pounds of CO₂ emitted per kilowatt-hour of electricity produced. Table 3.2-25 lists the CO₂ emission factors for typical fossil-fueled generating stations operating today. As shown in the table, combined cycle combustion turbines emit much less CO₂ than other types of fossil-fuel power plants. The estimated overall CO₂ emission factor for the proposed cogeneration facility is 0.83 pound per kilowatt-hour (lbs per kWhr).

Assuming an 85% capacity factor for the plant, the estimated annual CO₂ emissions from the cogeneration facility would be 2.2 million tons per year. Fugitive leaks of natural gas from the systems serving the proposed cogeneration facility are estimated to emit methane equivalent to 12% of the project's stack emissions of greenhouse gas (U.S. Department of Energy 2000b). The estimated greenhouse gas emissions generated by leaks from the supply pipelines serving the BP Cogeneration project would be 13,000 tons of methane per year.

Table 3.2-25: Typical CO₂ Emission Factors for Electrical Generating Stations

Generating Station Fuel Type	CO ₂ Emission Factor (lbs CO ₂ per kWhr)
BP Cogeneration Facility, natural gas-fired combined-cycle combustion turbine	0.83
Natural gas fuel combined-cycle combustion turbine	0.87
Natural gas fuel, conventional gas-fired boiler	1.32
Fuel oil, conventional oil-fired boiler	1.97
Coal, conventional coal-fired boiler	2.10
Other solid fuel generating stations	1.38
Nationwide average for electric utility generating stations (1998)	1.34

Sources: BP 2002; U.S. Department of Energy 2000; EFSEC 2002.

Mitigation Measures

The Applicant is proposing a greenhouse gas mitigation plan that would be flexible with respect to future changes in facility ownership.

As long as the proposed cogeneration facility is owned by the Applicant, the project's greenhouse gas emissions mitigation would be a part of BP's corporate greenhouse gas objective and the proposed project emissions would be offset by greenhouse gas emission reductions within BP worldwide operations. BP's worldwide objective is to hold net GHG emissions at the 2002 level of 90.8 tons (181.66 billion pounds) through the year 2012, while absorbing all new growth in BP company operations.

If, at some point in the future, the Applicant sells the proposed cogeneration facility, mitigation for proposed cogeneration facility greenhouse gas emissions would be provided as described below:

1. The proposed CO₂ emission limit would be 0.675 pound CO₂/kWh calculated on the basis of proposed cogeneration facility fuel charged to power in British thermal units per kilowatt hour (Btu/kWh).
 - a. Fuel charged to power equals (total fuel consumed by the cogeneration unit less fuel charged to steam) divided by net kWh generated.
 - b. Fuel charged to steam is equal to the steam energy used by the refinery divided by a conversion factor of 0.901 lower heating value/higher heating value.
2. Emissions in excess of the CO₂ emission limit would be mitigated either by:
 - a. an annual payment to a qualifying organization such as the Climate Trust of \$0.85/ton CO₂, or
 - b. Greenhouse gas reductions obtained by the proposed cogeneration facility owner, or
 - c. a combination of the two.

3. Mitigation would be satisfied annually for 30 years, which is the assumed economic life of the project. Mitigation would be reported to EFSEC annually.

3.2.6 Secondary and Cumulative Impacts

Cumulative Impact of Refinery and Cogeneration Facility Reductions

In combination with the removal of refinery utility boilers, the proposed cogeneration facility would result in an overall reduction in ambient concentrations of PM₁₀. These values represent the modeled impact of primary PM₁₀ emissions. Removal of the refinery boilers resulting from steam purchase from the cogeneration facility would significantly reduce NO_x emissions from the refinery, and would consequently also reduce secondary particulate in the airshed. The reduction in secondary particulate is expected to be greater than the increase in primary particulate emissions.

Bonneville Regional Air Quality Modeling Studies

In response to the regional boom in energy facility proposals which occurred in 2001-2002, and in order to address the cumulative impacts of the large number of proposals requesting interconnection with the federal transmission system, Bonneville initiated a Regional Air Impact Analysis to evaluate the impact of these facilities on airsheds in the Pacific Northwest. (Bonneville 2001a, 2001b, 2001c).

This study examines the potential contribution of the BP Cherry Point Project to regional haze in Class I areas within the Bonneville Service Area, the Columbia River Gorge National Scenic Area (CRGNSA), and the Mt. Baker Wilderness. Regional haze impacts are assessed following the techniques used in the Phase I study conducted by Bonneville. Bonneville's Phase I study examined potential air quality impacts associated with over 40 recently proposed power projects in the area. Based on the results of the Regional Air Quality Modeling Study, Bonneville is now examining potential cumulative regional haze impacts on a case-by-case basis for each new project before issuing a Record of Decision (ROD). Since it is unlikely all the proposed power plants will be built, the analysis investigates the cumulative impacts from a Baseline Source Group consisting of projects that have already been issued a ROD, other recently permitted power projects not requesting access to Bonneville's transmission grid but within the area, facilities well along in their permitting process, and the facility being considered for a ROD. The remainder of this section describes the Baseline Source Group, provides an overview of the dispersion modeling approach, presents the results of a cumulative analysis for the Baseline Source Group, and discusses the potential contribution of the BP Cherry Point Project to regional haze.

Phase I examined three scenarios regarding the number of future power plants to be operated in the region:

- A worst-case scenario in which a total of 45 new power plants were built and operated simultaneously at their rated capacity using their primary fuel for a total of more than 24,000 MW;

- A second scenario with 28 new power plants, totaling a little over 11,000 MW operated simultaneously by 2004; and
- A third scenario with 15 new power plants totaling 7,000 MW by 2004, which is the most likely scenario in the next 10 years based on projection of need for new energy.

Phase II attempted to model the individual contribution of each new plant to the overall cumulative impact. The Phase II analysis for the proposed cogeneration facility is essentially the same as the 7,000 MW scenario from Phase I.

Modeling Overview of Phase I

The dispersion modeling techniques used in the study are as follows:

- The study looked at two scenarios: (1) air impacts that would accrue if 28 of the projects were built and energized by 2004, and (2) air impacts that would occur if all 45 projects were built as planned and operated simultaneously.
- NO_x, PM₁₀, and SO₂ emissions from 45 proposed power projects with a combined capacity of more than 24,000 MW were considered in the analysis.
- The study evaluated impacts on 16 Class I/Scenic/Wilderness Areas (three National Parks, the Spokane Indian Reservation, and 12 wilderness areas), CRGNSA, and the Mt. Baker Wilderness Area.
- PM₁₀ concentrations include both primary and secondary aerosols, and the nitrogen deposition estimates include the ammonium ion.

Areas Showing Greatest Impact

Results showed that the greatest air quality impacts would occur in the Puget Sound lowlands from Centralia to Bellingham, in the Hermiston area, and in the eastern portions of the Lower Columbia River Basin.

Class II Significant Impact Levels Not Exceeded

With the exception of two receptors, predicted concentrations from the proposed power plants are less than the SILs for all pollutants and averaging periods. The peak PM₁₀ concentration occurred near the Wallula Gap. The predicted PM₁₀ concentration at this location was 4.54 µg/m³ because all of the plants are scheduled to be energized prior to 2004. The peak PM₁₀ concentration of all the proposed plants at this location was 12.4 µg/m³. The SILs were also exceeded in one other location; the 24-hour PM₁₀ SIL was exceeded at a receptor near the Tacoma tide flats, where the model predicts a 24-hour PM₁₀ concentration of 6.2 µg/m³. The SILs are thresholds used in the evaluation of individual, not multiple, facility impacts on the NAAQS.

National Ambient Air Quality Standards

This study has not examined local impacts from the power projects, but model results suggest that even if all the proposed power plants were energized, they are unlikely to exceed the NAAQS.

Proposed Class I Significant Impact Levels Exceeded at Several Locations

If all the plants scheduled to be energized before 2004 are built, their emissions are predicted to exceed the proposed 24-hour PM₁₀ Class I SIL (0.3 µg/m³) in the CRGNSA and in the Spokane Indian Reservation. When all 45 proposed sources were included in the model, the proposed 24-hour PM₁₀ Class I SIL was exceeded in 100 out of 18 Class I/Scenic/Wilderness Areas. However, Bonneville anticipates only a small portion of these plants will likely be built.

Increment Consumed

Predicted concentrations of PM₁₀, NO_x, and SO₂ from the proposed power projects are small fractions of the applicable Class I increments. For example, the peak PM₁₀ concentration was only 1.54 µg/ m³ in the CRGNSA, which is well below the 24-hour PM₁₀ Class I increment of 8 µg/ m³.

Nitrogen and Sulfur Deposition

Annual nitrogen and sulfur deposition predicted for the Class I/Scenic/Wilderness Areas, the CRGNSA, and the Mr. Baker Wilderness are less than 1% of the background deposition rates provided by the federal land managers for these areas.

Affected Visibility

The study results suggest the proposed power projects could degrade visibility in Class I areas, as characterized by guidance criteria established by the federal land managers. The model predictions indicate emissions from the plants scheduled to be energized prior to 2004 would degrade visibility on very clear days by more than 5% at 14 out of 18 Class I/Scenic/Wilderness Areas and by more than 10% at 8 areas. If all 45 of the proposed plants are built, visibility on very clear days has the potential to be frequently degraded by more than 10% at 12 out of 18 Class I/Scenic/Wilderness Areas and in the surrounding Class II areas. The sensitive areas most affected by the first group of plants (energized before 2004) are Mt. Rainier, the Alpine Lakes Wilderness, and the Mt. Baker Wilderness Areas. The inclusion of all proposed plants (pre- and post-January 2004) results in more than 10% change in visibility in 12 out of 18 of the Northwest's Class I/Scenic/Wilderness Areas.

Overview of Phase II

Peak emissions from the 15 projects within the Phase II Baseline Source Group, including the BP Cherry Point Project, are listed in Table 3.2-26. Emissions are shown both for primary and secondary fuels.

Table 3.2-26: Baseline Source Group Plus the BP Cherry Point Project Peak Emissions with Primary Fuel

No.	Project Name	Owner	MW	Peak Emissions (lb/hr)		
				SO ₂	NO _x	PM ₁₀
1	Fredonia Facility	PSE	108	3.5	23.2	6.8
2	Rathdrum Power, LLC	Cogentrix	270	2.7	29.8	21.4
3	Frederickson Power	West Coast	249	10.2	19.7	16.9
4	Coyote Springs 2	Avista	280	1.1	30.0	4.5
5	Goldendale Energy Project	Calpine	248	12.7	14.9	11.8
6	Hermiston Power Project	Calpine	546	2.5	71.7	38.1
7	Chehalis Generating Facility	Tractebel	520	20.8	40.9	31.6
8	Goldendale (The Cliffs)	GNA Energy	300	3.7	20.3	16.3
9	Big Hanaford Project	TransAlta	267	6.5	23.1	14.3
10	Mint Farm Generation	Mirant	319	4.0	25.1	23.1
11	Satsop CT Project - Phase I	Duke	650	6.7	43.4	47.0
12	Wanapa Energy Center	Confed.Tribes	1200	13.9	98.8	124.8
13	Plymouth Generation	NESCO	307	17.3	18.4	24.0
14	BP Cherry Point	BP NW Products	720	15.9	66.9	70.5
15	Summit/Westward (Clatskanie)	Summit	520	8.2	54.0	50.7
Total			6504	130	580	502
Peak Emissions with Secondary Fuel						
1	Fredonia Facility (Oil-Fired)	PSE	104	51.2	23.2	12.2
7	Chehalis (Oil-Fired)	Tractebel	520	238.0	211.5	40.0

The Fredonia Facility has requested fuel oil firing for all hours of the year as a secondary fuel. The Chehalis Generating Facility has requested fuel oil firing for 720 hours per year.

Operating Scenarios

The analysis assumes all plants in Table 3.2-26 are operating at peak load with their primary fuel for the entire simulation period. An oil-firing scenario was also considered, where sources permitted to fire with fuel oil were assumed to operate in this manner over the winter season. It is important to note that peak load operating assumptions likely overestimate impacts, and with the exception of the Fredonia Facility, the projects are not allowed to fire with fuel oil for an entire winter season. In practice, virtually all proponents state that they intend to burn gas except in times of significant shortage.

The oil-burning scenario is a compromise solution to a potentially complex assessment. The present analysis likely overstates potential impacts attributable to the Chehalis Generating Facility because it cannot burn oil every day of the winter. The meteorology on winter days producing the highest impacts may also not occur concurrently with the economic conditions likely to cause these power plants to burn oil. On the other hand, the impacts attributable to the Fredonia Facility (if they are allowed to burn oil every day) may be under-predicted because the analysis limits its oil-fired emissions to winter months.

Modeling Methods

- The CALPUFF dispersion model was applied to both of the simulations. CALPUFF is the EPA's preferred model for long-range transport assessments. CALPUFF treats plumes as a series of puffs that move and disperse according to local conditions that vary in time and space. CALPUFF estimates processes for wet and dry deposition, aerosol chemistry, and regional haze. The contribution of the BP Cherry Point Project to background extinction was assessed using the post-processing utilities included with the CALPUFF model system.
- Wind fields are based on the University of Washington's simulations of Pacific Northwest weather.
- The aerosol concentrations used to characterize background extinction coefficients in the study represent excellent visual conditions. Background visibility parameters are presented in Table 4 of the *Modeling Protocol*.
- The 432-mile by 418-mile study area includes Washington and portions of Oregon, Idaho, and British Columbia. Meteorological, terrain, and land use data were provided to the model using a horizontal grid mesh size of 7.5-mile. The terrain data are based on an average for each grid cell, thus the simulations do not fully resolve potential local impacts in complex terrain. A six-kilometer mesh size sampling grid was used with receptor locations within 16 Class I areas (3 National Parks, the Spokane Indian Reservation, and 12 wilderness areas), the CRGNSA, and the Mt. Baker Wilderness.
- Building downwash effects are not considered in the analysis, and emissions were characterized using a single stack for each facility.

Phase II Results

The CALPUFF modeling system was applied to simulate emissions from the Baseline Source Group using a year of Pacific Northwest weather. The 24-hour average extinction coefficient was used as a measure of regional haze. The analysis predicted the number of days for each season with greater than 5% and 10% change to background extinction (measure of light), respectively. For both the annual natural gas and the winter oil-fired scenarios, the Baseline Source Group could result in a "just perceptible" change to the extinction coefficient on a few days for several of the areas examined in the study. The areas most affected are the Class I areas near the CRGNSA, Olympic National Park, Mt. Rainier National Park, and the Alpine Lakes Wilderness. In Mt. Rainier National Park, the predicted change to background extinction for the winter oil-fired case exceeds the 10% significance criterion on six days. The Baseline Source Group does not exceed the 10% significance criterion on any days when these sources are fired by natural gas.

Potential changes to background extinction due to emissions from the BP Cherry Point Project to Class I areas, the CRGNSA, and the Mt. Baker Wilderness were evaluated. The modeling suggests the proposed facility could increase daily background extinction by up to 8.05%, 2.23%, and 3.21% in the Mt. Baker Wilderness, the North Cascades National Park, and Olympic National Park, respectively. The project would contribute greater than 0.4% on only one day in any one area when the combined group's contribution is greater than 5% and on no days when the group's contribution is greater than 10%. The project would not significantly contribute to

regional haze at any of the Class I areas within the Bonneville Service Area, the CRGNSA, or the Mt. Baker Wilderness when the facilities considered in this analysis are fired by natural gas.

The project's contribution to predicted changes in extinction for the winter oil-fired scenario was also evaluated. This figure was constructed from the highest 24-hour extinction coefficient at each receptor predicted for the project during a winter simulation. The project's contributions are not significant on any of the six days when the Baseline Source Group's combined change in extinction is greater than 10% in Mt. Rainier National Park.

Cumulative Impact of Greenhouse Gas Emissions

Global warming is a worldwide problem caused by the combined greenhouse gas emissions throughout the planet. CO₂ emitted from an industrial facility persists in the atmosphere for over 100 years before it is eventually metabolized by plants or absorbed into the oceans (ICPP 2001a). During that 100-year lifetime, a parcel of emissions generated anywhere on the planet will disperse throughout the world and affect climate change everywhere. Thus, climate change in Washington would be affected as much by emissions from power plants in China, for example, as by emissions from the proposed project. To provide perspective on the potential direct impacts of emissions from the proposed project, it is necessary to consider worldwide emissions. Table 3.2-27 lists greenhouse gas emissions worldwide, from the U.S., and from the State of Washington. The table also lists the total estimated future greenhouse gas emissions from the new gas-fired power plants forecast to be built in the Pacific Northwest (Bonneville 2001a).

Many air pollutants compose "greenhouse gases," each of which exhibits a different chemical tendency to affect global warming. The two most common greenhouse gases associated with gas-fired power plants are CO₂ emitted from the exhaust stacks and methane emitted as fugitive leaks of natural gas along pipeline systems. Emissions of various greenhouse gas chemicals are commonly standardized as "carbon equivalents." The emission rates listed in Table 3.2-27 are standardized as million metric tons of carbon equivalents (MMTCE) per year, to account for the different global warming potential of each greenhouse gas. For comparison, 1 million tons of CO₂ equals 0.25 MMTCE, and 1 million tons of methane equals 5.2 MMTCE.

As listed in the table, most of the worldwide greenhouse gas emissions are in the form of CO₂, while a smaller fraction of the emissions are in the form of other gases such as methane or nitrous oxide. The total annual CO₂ emissions associated with the cogeneration facility would be 0.56 MMTCE if the facility operates at 85% capacity. Based on the data listed in Table 3.2-27, this is 2.5% of the greenhouse gas presently emitted from all sources in Washington State and 5.1% of the amount anticipated to be issued from all proposed future power plants in the Northwest, assuming all of these plants were constructed. The greenhouse gas emissions from the cogeneration facility would be approximately 0.03% of the U.S. emissions. The actual effect on global warming caused solely by emissions from the cogeneration facility is unknown. However, a cogeneration facility produces less greenhouse gas emissions per kilowatt hour of electricity produced than a combined-cycle facility with no cogeneration capability. In a regional perspective, the production of greenhouse gases could be reduced if operation of the BP cogeneration facility displaces the operation of other non-cogeneration facilities.

Table 3.2-27: Comparison of Worldwide vs. Local Greenhouse Gas Emissions

Item	Annual Greenhouse Gas Emissions (MMTCE per year)		
	CO ₂	Compounds other than CO ₂	Total
Worldwide emissions (including U.S. in 1998)	5,660	2,430	8,090
United States Emissions (1998)	1,494	340	1,834
Washington State Emissions (1995)	21	4	25
Anticipated future gas-fired power plants in Washington and Oregon (28 plants, 11,000 MW)	11	1.3	12.3
Proposed BP Cherry Point Cogen emissions at 85% capacity	0.55	0.07	0.63

Sources: IPCC 2001; EPA 2000; CTED 1999

MMTCE – million metric tons of carbon equivalent

The refinery would also realize a net reduction of CO₂ emissions from the purchase of steam from the cogeneration facility rather than production onsite in refinery boilers. The Applicant has estimated that approximately 440,000 tons per year of CO₂ emission reduction would occur in this manner.

Cumulative Impacts of the BP Cogeneration Facility and the Sumas Energy 2 Generation Facility

In response to a scoping comment, the cumulative impacts of the BP cogeneration facility and Sumas Energy 2 Generation Facility were estimated for the Sumas/Abbotsford area, and compared with the respective standards and objectives in Tables 3.2-28 and 3.2-29. These tables provide a conservative estimate of the cumulative impact of both facilities, considering that the estimates provided for the BP facility might not correspond to identical meteorological conditions under which the SE2 emissions were evaluated. Therefore, conservatively, the cumulative emissions from both of these facilities would be below the applicable standards or objectives.

Georgia Strait Crossing Project

The proposed GSX project would be located within the proposed cogeneration project site, and both projects could have the same construction time frame. The GSX project involves construction and operation of a pipeline that would transport natural gas from existing systems at the U.S./Canada border near Sumas, Washington, to an interconnect pipeline proposed by Canada in Boundary Pass in the Strait of Georgia. The system would consist of an onshore and offshore pipeline, interconnect facilities, one new natural gas compressor station, and related facilities. Within a stretch of less than a mile, the cogeneration project and the GSX project would share a common project area. This pipeline would involve many construction activities, some of which include clearing, grading, trenching, and backfilling. Since the proposed GSX and cogeneration project might coincide, cumulative dust generation (i.e., particulate matter) would be a possible side effect.

Emissions during the construction of both projects would consist of fugitive dust and combustion exhaust from construction equipment and vehicles. However, with proper mitigation measures (see Section 3.2.7) dust and emission production would be minimal.

Table 3.2-28: Cumulative Total Concentrations Compared to Canadian Air Quality Objective

Criteria Pollutant	Averaging Time	Highest and Cumulative Concentrations ($\mu\text{g}/\text{m}^3$)				Most Stringent of Canadian Objective ($\mu\text{g}/\text{m}^3$)
		Maximum Existing Background Concentration ^{2,3} ($\mu\text{g}/\text{m}^3$)	Modeled Maximum Impacts of Sumas Energy 2 ($\mu\text{g}/\text{m}^3$) ¹	Modeled Maximum Impacts of BP Cogeneration Facility in Abbotsford ($\mu\text{g}/\text{m}^3$)	Cumulative Impact ($\mu\text{g}/\text{m}^3$)	
SO ₂	annual	3	0.13	0.0014	3.13	25
	24-hour	8	1.22	0.58	9.80	150
	three-hour	21	4	0.353	25.35	375
	one-hour	29	5.13	1.04	35.17	450
PM ₁₀	annual	14	0.38	0.0079	14.39	30
	24-hour	36	3.67	0.16	39.83	50
CO	eight-hour	3,480	3.32	0.45	3,484	5,500
	one-hour	6,960	6.5	2.7	6,969	14,300
NO ₂	annual	29	0.26	0.006	29.27	60
	24-hour	73	2.54	0.12	75.66	200
	one-hour	109	10.73	3.2	122.93	400

Source: BP 2002, GVRD 1999, 2000, 2001

1 Modeled maximum impacts of Sumas Energy 2 are taken from the SE2 Second Revised Application dated June 29, 2001, Table 6.1-16.

2 Maximum concentration from a three year monitoring period (1999, 2000, 2001).

Table 3.2-29: Cumulative Total Concentrations Compared to NAAQS or WAAQS

Criteria Pollutant	Averaging Time	Highest and Cumulative Concentrations ($\mu\text{g}/\text{m}^3$)				Most Stringent of either the NAAQS or WAAQS ($\mu\text{g}/\text{m}^3$)
		Maximum Existing Background Concentration ^{2,3} ($\mu\text{g}/\text{m}^3$)	Modeled Maximum Impacts of Sumas Energy 2 ($\mu\text{g}/\text{m}^3$) ¹	Modeled Maximum Impacts of BP Cogeneration Facility in Sumas ($\mu\text{g}/\text{m}^3$)	Cumulative Impact ($\mu\text{g}/\text{m}^3$)	
SO ₂	annual	3	0.13	0.0046	3.13	80
	24-hour	8	1.4	0.13	9.53	365
	three-hour	21	3	0.57	24.6	1,300
	one-hour	29	6.97	1.7	37.7	1,065
PM ₁₀	annual	14	0.39	0.027	14.4	50
	24-hour	36	4.23	0.43	40.7	150
CO	eight-hour	3,480	4.57	0.81	3,485	10,000
	one-hour	6,960	8.82	4.4	6,973	40,000
NO ₂	annual	29	0.27	0.021	29.3	100

Source: BP 2002, GVRD 1999, 2000, 2001

1 Modeled maximum impacts of Sumas Energy 2 are taken from the SE2 Second Revised Application dated June 29, 2001, Table 6.1-16.

2 Maximum concentration from a three year monitoring period (1999, 2000, 2001).

3.2.7 Mitigation Measures

Construction

Mitigation Proposed by the Applicant

Any emission of fugitive dust requires implementation of Best Management and Good Construction Practices. Incorporating mitigation measures into the construction specifications for the project would reduce construction impacts. Possible mitigation measures to control PM₁₀, particulate matter deposition, and emissions of CO and NO_x during construction are listed below.

- Spraying exposed soil with water would reduce PM₁₀ emissions and particulate matter deposition. Water would be applied at a rate to maintain a moist surface, but not create surface water runoff or erosion conditions.
- Providing wheel washers to remove particulate matter that would otherwise be carried offsite by vehicles would decrease deposition of particulate matter on area roads and subsequent entrainment from those roads.
- Removing mud deposited on paved, public roads would reduce particulate matter in the area.
- Routing and scheduling construction trucks to reduce delays to traffic during peak travel times would reduce secondary air quality impacts caused by a reduction in traffic speeds while waiting for construction trucks.
- Requiring appropriate emission-control devices on all construction equipment powered by gasoline or diesel fuel would reduce CO and NO_x emissions in vehicular exhaust. Using relatively new, well-maintained equipment would reduce CO and NO_x emissions.
- Planting vegetative cover as soon as possible after grading would reduce windblown particulate matter in the area.

Additional Recommended Mitigation Measures

- Covering all trucks transporting materials, wetting materials in trucks, or providing adequate freeboard (space from the top of the material to the top of the truck) would further reduce PM₁₀ and deposition of particulate matter during transportation.

Operation and Maintenance

Regulated Air Emissions

The Applicant would mitigate air emissions from the proposed cogeneration facility by burning only natural gas in the combustion turbines and duct burners and only low-sulfur diesel fuel in the emergency generator and firewater pump. Over and above the CGT vendor's 9.0 ppm dry, low NO_x technology, NO_x emissions from the CGTs and duct burners would be controlled to the BACT level (2.5 ppm annual average at 15% O₂) through the use of SCR. A catalytic oxidation system would be installed for the control of CO emissions from the CGTs and duct burners to an annual level of 2 ppm (at 15% O₂). This catalytic oxidation system would also provide the added benefit of controlling about 30% of the VOC emissions, including toxic air pollutants. Other

pollutants would be controlled using good combustion technology and good operating practices and the combustion of low-sulfur natural gas as a fuel (BP 2002, Appendix E).

The Applicant would control dust on all the proposed cogeneration facility roads and would provide necessary maintenance and housekeeping to minimize the amount of dust that could be generated from vehicle traffic.

Additional Mitigation Measures

The Applicant has proposed reductions in refinery emissions through removal of the steam boilers. Because the air emissions from the refinery and the cogeneration facility would be regulated by different state jurisdictions (Ecology for the refinery, and EFSEC for the cogeneration facility), it's unclear which jurisdiction will enforce these reductions in refinery emissions. Enforceable conditions requiring removal of the refinery's three utility boilers within six months of the beginning of cogeneration facility operation could allow regulatory agencies to more fully take into account refinery emission reductions in the permitting and environmental review processes.

Greenhouse Gas

As long as the proposed cogeneration facility is owned by the Applicant, the project's greenhouse gas emissions mitigation would be a part of BP's corporate greenhouse gas objective and the proposed project emissions would be offset by greenhouse gas emission reductions within BP worldwide operations. BP's worldwide objective is to hold net GHG emissions at the 2002 level of 90.8 tons (181.66 billion pounds) through the year 2012, while absorbing all new growth in BP company operations.

If, at some point in the future, the Applicant sells the proposed cogeneration facility, mitigation would be provided for greenhouse gas emissions in excess of 0.675 pound CO₂/kWh in the form of an annual payment to a qualifying organization such as the Climate Trust of \$0.85/ton CO₂, or greenhouse gas reductions would be obtained by the proposed cogeneration facility owner, or a combination of the two. Mitigation would be satisfied annually for 30 years, which is the assumed economic life of the project. Mitigation would be reported to EFSEC annually.

3.2.8 Significant Unavoidable Adverse Impacts

No significant unavoidable adverse impacts on air quality are identified. The proposed cogeneration facility would emit criteria air pollutants and toxic air pollutants into the atmosphere. It could also enable the refinery to implement significant emission reductions. If such emission reductions were implemented, it is likely there would be no observable changes in ambient air quality levels, either in the U.S. or in Canada. The various analyses conducted for the PSD application and for other sensitive areas of interest indicate that air emissions associated with the proposed cogeneration facility would occur and would have an impact on the overall air quality of the region. Those emissions are not likely to cause any adverse impacts to the protection of human health and welfare, to any soils, vegetation, flora, or fauna, or to any other

sensitive areas identified by the National Parks Service, U.S. Fish and Wildlife Service, U.S. Forest Service, or by Canadian air quality regulatory agencies.